

## SECTION 5

### EMISSIONS FROM FUEL PRODUCTION AND DISTRIBUTION PROCESSES

This section discusses emissions from feedstock extraction, fuel production, and distribution. The emissions sources are covered roughly in order from extraction through distribution with some overlap. Section 5.1 reviews emission rates from equipment used in transporting feedstocks and fuel and in processing operations. Energy usage rates for transportation equipment is also discussed in Section 5.1.

Fuel production emissions and energy inputs are covered in Section 5.2. Fuel processing is defined as the conversion of feedstock material into end use fuel, or fuel production Phase 3. Feedstock input requirements also relate to feedstock extraction requirements in Section 5.1. Gaseous fuel liquefaction is included Phase 3. Several fuels are processed from a combination of feedstocks and process fuels. Oil refineries and gas treatment plants produce multiple fuel products and some ethanol plants produce animal feed byproducts, many production facilities import or export electricity. The allocation of energy use to product fuels is discussed in Section 5.2.

Several approaches have been taken towards determining fuel-cycle emissions. Perhaps the simplest approach is to estimate the energy required for each step of the fuel-cycle. Then, "emission factors" can be multiplied by the energy use rate (Jenkins, 1979, Unnasch, April 1990). There are several negative aspects of relying entirely on this approach. Primarily, energy use expressed in Btu/gal of fuel (or Btu/Btu fuel) is many steps removed from the actual fuel-cycle processing step.

For example, consider a gasoline deliver truck with 8000 gal of fuel traveling a 100 miles round trip route. A diesel truck fuel consumption of 5 mi/gal is expressed in energy terms as 0.0028 Btu/Btu based on lower heating values (Table 2-1). Expressing all of the fuel processing steps in energy terms allows for a convenient comparison amongst different fuel-cycle emission studies. The emissions in this study are estimated from more fundamental principles. In the case of fuel delivery trucks, a constant mileage is assumed for all fuel types and emissions are calculated from the g/miles emissions and truck fuel capacity to yield g/gal of delivered fuel.

The energy in Btu (HHV) per unit of fuel produced is tracked with the fuel-cycle emissions. Lower heating values are only used to estimate vehicle fuel consumption and are not mixed with higher heating values anywhere in this study.

Emission rates from fuel production equipment are estimated from published emission factors, other emissions data, and emission requirements from local and federal rules. In the strictest sense, an emission factor might be considered to be an energy specific emission rate, in g/gal fuel for example, that represents a wide range of equipment and is weighted according to equipment inventory, usage pattern, and other parameters. The term emission factor implies inventory wide accuracy and is reserved for published emission rates.

Emissions depend on the location of equipment and the prevailing (and prior) emission standards. Vehicles and combustion equipment in the South Coast Air Basin are and will continue to be subject to the strictest emission controls.

Table 5-1 summarizes emissions requirements that affect fuel production equipment in the U.S. and South Coast Air Basin. SCAQMD limits are as stringent or more so than NSPS and NESHAPS standards. Table 5-2 shows  $\text{NO}_x$  limits on combustion sources in the South Coast Air Basin. Boilers and gas turbines have been subject to Best Available Control Technology (BACT) requirements since the 1980s. All equipment installed since that time would meet  $\text{NO}_x$  levels consistent with Rule 474. More recent installations will need to meet stricter  $\text{NO}_x$  limits under Rule 1134.  $\text{NO}_x$  levels of 9 ppm can only be met with Selective Catalytic Reduction (SCR) and actual emissions with SCR are half of the limit.

Emission limits under Rules 474, 1110, 1134, and 1146 are expressed in ppm. These ppm levels were converted to  $\text{lb NO}_2/\text{MMBtu}$  using a fuel factor of 8740 dry scf/MMBtu for natural gas and 9220 dry scf/MMBtu for diesel fuel. These emissions are expressed in  $\text{lb/MWh}$  or  $\text{g/hp-hr}$  for the energy consumption assumptions shown in Table 5-2.

## **5.1 FUEL EXTRACTION, TRANSPORTATION, AND PROCESSING EQUIPMENT**

Several types of equipment are used repeatedly throughout the estimation of fuel-cycle emissions. For example, diesel powered tanker trucks are used to move gasoline, diesel, LPG, and alcohol fuels from storage locations. Natural gas engines and gas turbines compress natural gas and are used in a variety of fuel industry applications. This section summarizes the emissions and estimated usage rates for various types of equipment. The usage rates are related to assumptions for different scenarios.

### **5.1.1 Engine Emissions**

Table 5-3 summarizes the emission and performance characteristics of natural gas turbines used for natural gas transmission, prime movers. Table 5-3 shows estimate of current and future emissions for turbines operating in the South Coast Air Basin, California, and the U.S. Turbines operating outside of North America are assumed to emit at 1990 U.S. levels. The table also presents AP-42 emission factors for comparison (U.S. EPA, AP-42). Note, the AP-42 emission factors represent uncontrolled gas turbines. Methane and CO levels are consistent with values used in this study.

Emissions in Table 5-3 are shown in  $\text{g/bhp-hr}$ . These are converted to  $\text{g/100 scf}$  of natural gas transmitted with usage rates discussed later and the calculation approach in Section 5.4. The source code identifies where the emission rates are located in the emissions data base (EFAC in Appendix B).

Based on a population profile of gas turbines used as natural gas prime movers (Huey, 1993) and emissions data for individual makes and models of gas turbines (Urban, 1980 and Fanick, 1988), the energy consumption to energy produced (energy rate) for gas turbines is estimated to be 11,000 Btu/bhp-hr. However, the range of energy rates for gas turbine prime movers can vary from 10,000 to 13,000 Btu/bhp-hr.

**Table 5-1. Summary of emission regulations**

<b>New Source Performance Standards (NSPS)</b>	
Subpart J	Standards of Performance for Petroleum Refineries
Subpart K	Standards of Performance for Storage Vessels for Petroleum Liquids
Subpart Y	Standards of Performance for Coal Preparation Plants
Subpart GG	Standards of Performance for Stationary Gas Turbines
Subpart XX	Standards of Performance for Bulk Gasoline Terminals
Subpart GGG	Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries
Subpart KKK	Standards of Performance for Equipment Leaks of VOC from On-shore Natural Gas Processing Plants
Subpart QQQ	Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems
<b>National Emission Standards for Hazardous Air Pollutants (NESHAPS)</b>	
Subpart J	National Emission Standard for Equipment Leaks (Fugitive Emission Sources) for Benzene
Subpart V	National Emission Standard for Equipment Leaks (Fugitive Emission Sources)
<b>South Coast Air Quality Management District (SCAQMD)</b>	
<b>Regulation IV — Prohibitions</b>	
Rule 432	Gasoline Specifications
Rule 461	Gasoline Transfer and Dispensing
Rule 466	Pumps and Compressors
Rule 466.1	Valves and Flanges
Rule 474	Fuel Burning Equipment — Oxides of Nitrogen
<b>Regulation XI — Source Specific Standards</b>	
Rule 1109	Emissions of Oxides of Nitrogen for Boilers and Process Heaters in Petroleum Refineries
Rule 1110 (.1 & .2)	Emissions from Stationary Internal Combustion Engines (gaseous- and liquid-fueled)
Rule 1134	Emissions of Oxides of Nitrogen from Stationary Gas Turbines
Rule 1135	Emissions of Oxides of Nitrogen from Industrial, Institutional and Commercial Boilers, Steam Generators, and Process Heaters
Rule 1148	Thermally Enhanced Oil Recovery Wells
Rule 1149	Storage Tank Degassing
Rule 1158	Storage, Handling and Transport of Petroleum Coke
Rule 1170	Methanol Compatible Fuel Storage and Transfer
Rule 1173	Fugitive Emissions of Volatile Organic Compounds

**Table 5-2. Summary of SCAQMD NO<sub>x</sub> rules**

Rule 474 — Fuel Burning Equipment — Oxides of Nitrogen								
Emission Source	Non-Mobile Fuel Burning Equipment						Steam Generating Equipment	
Heat Rate (MBtu/hr)	555 to 1,785		1,786 to 2,142		>2,143		>555	
Fuel	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil
<b>NO<sub>x</sub> Emissions</b>								
(ppmvd @ 3% O <sub>2</sub> )	300	400	225	325	125	225	125	225
(lb/MMBtu)	0.37	0.52	0.28	0.42	0.15	0.29	0.15	0.29
Rule 1109 — Emissions of Oxides of Nitrogen for Boilers and Process Heaters in Petroleum Refineries								
Emission Source	Boilers and Process Heaters in Petroleum Refineries							
NO <sub>x</sub> (lb/MMBtu)	0.03							
Rule 1110.2 — Emissions from Stationary Internal Combustion Engines (gaseous- & liquid-fueled)								
Emission Source	Stationary Internal Combustion Engines							
Energy Consumption (Btu/bhp-hr)	8000							
<b>NO<sub>x</sub> Emissions</b>								
(ppmvd @ 15% O <sub>2</sub> )	36							
(lb/MMBtu)	0.121							
(g/bhp-hr)	0.44							
Rule 1134 — Emissions of Oxides of Nitrogen from Stationary Gas Turbines								
Emission Source	Simple Cycle	Simple Cycle	Simple Cycle No SCR	Simple Cycle	Simple Cycle No SCR	Combined Cycle No SCR	Combined Cycle	
Unit Size (MW)	0.3 to 2.9	2.9 to 10	2.9 to 10	>10	>10	>60	>60	
Energy Consumption (Btu/hp-hr)	13,000	13,000	11,000	11,000	11,000	6,000	6,000	
<b>NO<sub>x</sub> Emissions</b>								
(ppmvd @ 15% O <sub>2</sub> )	25	9	14	9	12	15	9	
(lb/MMBtu)	0.093	0.0337	0.052	0.0337	0.044	0.056	0.0337	
(g/hp-hr)	0.55	0.20	0.26	0.17	0.22	0.15	0.092	
(lb/MWh)	0.90	0.59	0.77	0.50	0.65	0.45	0.27	
Rule 1146 — Emissions of Oxides of Nitrogen for Industrial, Institutional, and Commercial Boilers and Process Heaters								
Emission Source	Industrial, Institutional, and Commercial Boilers and Process Heaters							
NO <sub>x</sub> (lb/MMBtu)	0.037							

**Table 5-3. Natural gas turbine emissions**

Turbine location	AP-42 Factor	South Coast Air Basin		California, U.S.	
Year		1993	2010	1993	2010
Energy Rate (Btu/bhp-hr)		11,000	11,000	11,000	11,000
<b>Emissions (g/bhp-hr)</b>					
NO <sub>x</sub>	1.3 <sup>a</sup>	0.4	0.17	1.7	1.0
CO	0.55	0.83	1.0	0.83	1.0
CO <sub>2</sub>	405 <sup>b</sup>	599	599	599	599
CH <sub>4</sub>	0.17	0.17	0.2	0.17	0.2
NMOG	0.01	0.01	0.01	0.01	0.01
Source code <sup>c</sup>	—	n52.1	n52.2	n52.3	n52.4
Reactivity code	—	0007	0007	0007	0007
Data source	AP-42 7/93	Huey	EE <sup>d</sup>	Huey	EE

<sup>a</sup>NSPS for NO<sub>x</sub> is 1.39 g/bhp-hr, SCAQMD rule 1134 requirements are equivalent to 0.1 to 0.5 g/bhp-hr.

<sup>b</sup>AP-42 Emission factor is the same for gas turbines and internal combustion engines which is not consistent with expected engines efficiency.

<sup>c</sup>Source codes in this report refer to emission factors in the EFAC data base in Appendix B.

<sup>d</sup>Engineering estimate. BACT for gas turbines will result in 0.03 g/bhp-hr. Newer gas turbines without SCR will have low-NO<sub>x</sub> configurations.

The current NO<sub>x</sub> emission estimate for gas turbines located in the South Coast Air Basin is based on SCAQMD Rule 1134 (Emissions of Oxides of Nitrogen from Stationary Gas Turbines) and an estimate of the types of gas turbines in the region. Because the NO<sub>x</sub> limit set forth in Rule 1134 varies according to control technology and rated power output, the NO<sub>x</sub> emission factor is an average emission factor for several types of gas turbines with varying power output and control technologies. The future NO<sub>x</sub> emission factor for gas turbines in the South Coast Air Basin is based on the emissions from BACT for gas turbines.

The current NO<sub>x</sub> emission factor assigned to gas turbines located outside the South Coast Air Basin (California and the U.S.) is based on a gas turbine prime mover population profile and emissions data for those gas turbines. Assuming a greater use of NO<sub>x</sub> controls, the future NO<sub>x</sub> emission factor assigned to California and the U.S. will be lower than the current NO<sub>x</sub> emission factor.

Current CO and HC emissions for all turbines in the United States are based on a population profile of the gas turbine prime movers (Huey, 1993) and emissions data (Urban, 1980 and Fanick, 1988) for uncontrolled gas turbines. By assuming a greater use of NO<sub>x</sub> control technologies in the future, CO and HC emissions for all future turbines should increase slightly. For very lean operation, CO and HC emissions increase as NO<sub>x</sub> emission decrease. The emissions data also show that methane emissions make up more than 90 percent of the THC emissions from a gas turbine.

Table 5-4 summarizes the emission and performance characteristics of natural gas reciprocating engines used for natural gas transmission, prime movers. Table 5-4 estimates current and future emission rates for engines operating in the South Coast Air Basin, California, and the U.S. Engines outside of North America are assumed to emit at the 1990 U.S. level. The table also presents AP-42 emission factors for comparison (U.S. EPA, AP-42, Chapter 3, 1985). Note, the AP-42 emission factors represent uncontrolled reciprocating engines.

Based on a population profile of reciprocating engines prime movers (Huey, 1993) and emissions data for individual makes and models of engines (Urban, 1980 and Fanick, 1988), the energy consumption for engines is estimated to be 8,000 Btu/bhp-hr. This value can range from 6,000 to 10,000 Btu/bhp-hr.

Population profiles of reciprocating engine prime movers indicate that, the majority of these engines are lean-burn with relatively few being stoichiometric or rich-burn engines. The emission

**Table 5-4. Natural gas reciprocating engine emissions**

Engine Location	AP-42 Factor	South Coast Air Basin		California, U.S.	
Year		1990	2010	1990	2010
Energy Rate (Btu/bhp-hr)		8,000	8,000	8,000	8,000
<b>Emissions (g/bhp-hr)</b>					
NO <sub>x</sub>	11.0 <sup>a</sup>	2	0.44	6	2
CO	1.4	2.65	3	2.65	3
CO <sub>2</sub>	405	463	463	463	463
CH <sub>4</sub>	5.6	4.42	5	4.42	5
NMOG	0.43	0.45	0.5	0.45	0.5
Source code	—	n51.1	n51.2	n51.3	n51.4
Reactivity code	—	1001	1001	1001	1001
Data source	AP-42 7/93	Huey	EE <sup>b</sup>	Huey	EE

<sup>a</sup>SCAQMD rule 1110.2 requirements are equivalent to 0.34 to 0.61 g/bhp-hr.

<sup>b</sup>Engineering estimate.

factors assigned to reciprocating engine prime movers are associated with lean-burn engines. Uncontrolled lean burn engines do not operate sufficiently lean to provide significant NO<sub>x</sub> reductions. All new lean burn engines sold in North America are configured for low NO<sub>x</sub> emissions.

NO<sub>x</sub> emissions outside the South Coast Air Basin (California and the U.S.) are estimated to be 6 g/bhp-hr, which is based on an engine prime mover population and emissions profile. NO<sub>x</sub> emissions for an uncontrolled lean-burn prime mover range from 10 to 12 g/bhp-hr, whereas the emissions for a controlled lean-burn prime mover are about 1 to 2 g/bhp-hr (Huey, 1994). This study assumes that roughly half of the engine prime movers outside the South Coast Air Basin are controlled.

NO<sub>x</sub> emissions for the South Coast Air Basin and future NO<sub>x</sub> emissions for California and North America are estimated to be 2 g/bhp-hr, which is equivalent to a controlled lean-burn engine. Future NO<sub>x</sub> emissions for engines located in the South Coast Air Basin are estimate to 0.48 g/bhp-hr, based on SCAQMD Rule 1110.2 (Emissions from Stationary Internal Combustion Engines).

Current CO and HC emissions for all engine prime movers in the U.S. are based on a population profile of the gas turbine prime movers (Huey, 1993) and emissions data (Urban, 1980 and Fanick, 1988) for uncontrolled engines and are consistent with AP-42 factors. Future CO and HC emissions for all engines in the U.S. should increase slightly due to the greater use of NO<sub>x</sub> control technologies. Generally CO and HC emissions increase as NO<sub>x</sub> emission decreases. Similar to gas turbines, the emissions data also show that methane emissions makes up over 90 percent of the VOC emissions from an engine.

Table 5-5 shows the mix of distribution equipment and distances for natural gas transmission. In the future, natural gas for incremental CNG fueling will come from Canada and Texas (Thomason, 1993). The pipeline distances are apportioned according to their geographic location and represented as a percentage of 1000 mi. Note that the total for the year 2010 equals 135 percent or 1350 mi. These values are inputs into the calculation data base discussed in Section 5.4. Current average natural gas use represents a mix including gas from Southern California. The allocation percentages are weighted according to estimated gas usage from different sources.

Natural gas is also a feedstock for LNG, hydrogen, and methanol production. When fuels are produced outside of Southern California, a natural gas transmission distance of 200 miles is assumed. Scenario 3 and 4 assume LNG liquefaction within the South Coast Air Basin and requires transportation into Southern California. LPG is a byproduct of natural gas production. Propane is produced at gas treatment plants and natural gas does not require significant transmission energy.

#### **5.1.1.1 Farm Equipment**

Fuels and feedstocks are transported and distributed by a variety of equipment including trucks, trains, and marine vessels. Emissions from fuel or material transport were determined from emission rates and equipment usage factors that take into account distance traveled and cargo load. The emissions and use factors for the relevant fuels are discussed for each transportation mode. Several types of biomass are potential feedstocks for fuel production. Ethanol is currently produced from corn, sugar cane, and waste starch products. The U.S. DOE has explored numerous approaches for producing fuels from biomass (Ferrell, 1993). Most of the DOE's development work has been aimed at ethanol production through enzymatic hydrolysis. This process can convert cellulosic

**Table 5-5. Overview of natural gas pipeline transmission**

Year	1990	2010
Equipment	55% recip. <sup>a</sup> engines 45% gas turbines	50% recip. engines 50% gas turbines
Fuel used by equipment	Natural gas	Natural gas
<b>NG transport for CNG<sup>b</sup></b> Routes, distance to Southern California (mi)	Average, 1000	W. Texas, 1350 CA portion, 50 <sup>c</sup> Alberta Canada, 1350 CA portion, 400 <sup>c</sup>
<b>NG transport allocation</b> (% of 1000 mi)	SC-5% <sup>d</sup> CA-25% US-66% ROW-6%	SC-5% CA-23% US-97% ROW-10%
Source code	n51, n52	n51, n52
<b>NG transport for LNG Scenario 1</b> Distance to plant (mi)	Wyoming, 200	Algeria, 200
<b>Methanol feedstock transport</b> Distance to plant (mi)	ROW, 200	ROW, 200
<b>Hydrogen and LNG feedstock transport Scenarios 2, 3, 4</b> Distance to plant (% of 1000 mi)	—	CA-23% US-97% ROW-10%
Use factor (hp-hr/MMscf/mi)	0.9	0.9

<sup>a</sup>Recip. = Reciprocating, 1990 equipment mix from Thomason, 2010 estimate from Acurex Environmental (Huey).

<sup>b</sup>CNG = Compressed natural gas.

<sup>c</sup>The distance traveled in California depends on the pipeline path. For natural gas from Texas, the portion traveled in California is 50 miles.

<sup>d</sup>The allocation percentage is an input into the VIEW spreadsheet model. The numbers do not add to 100% but rather represent the fraction of 1000 miles. Therefore, 5% corresponds to 50 miles in the SCAQMD and 25% corresponds to 250 miles traveled in California.

feedstocks to ethanol. Such feedstocks include agricultural wastes, wood waste, and purpose grown energy crops. Potential energy crops include poplar (a fast-growing tree) and switch grass. Waste biomass resources in California, if entirely converted to ethanol, can produce about 400 million gallons per year which would be sufficient to meet near term alternative fuels demand. Farming and feedstock transportation requirements for energy crops were used to estimate fuel usage in this study. These energy requirements for purpose farmed biomass are higher than those for waste feedstocks and represent a conservative estimate.

Emission factors from an ARB study on farming equipment are shown in Table 5-6 (Kreebe, 1992). The study considered a range of equipment power which did not vary substantially (for the overall emission factor) in  $\text{NO}_x$ . The most prominent size range for agricultural equipment is used in this study. Typical energy consumption values are assumed for diesel equipment and increased by 20 percent for gasoline.

Evaporative emissions were estimated from ARB's study on off-road emissions. For the 40 to 100 hp category of agricultural equipment, evaporative emissions were 550 lb/unit per year of which 98 percent were running losses. Running losses in the ARB study were based on the EMFAC emission factor for uncontrolled automobiles. The study indicates 5248 operating hours per year and 32,906 gallons per year of fuel use for 70 hp equipment. The evaporative emissions are then 7.6 g/gal. An additional 4.6 g/gal was added for uncontrolled fueling emissions from Section 5.2. Evaporative emissions for RFG- and diesel- fueled equipment were adjusted for the vapor pressure in proportion to the mass emissions in Section 5.2. Emission factors from AP-42 indicate lower  $\text{NO}_x$  for diesel and higher  $\text{NO}_x$  for gasoline engines and are shown for comparison in Table 5-7. Emission rates in this study are based on the ARB study which is a more recent evaluation. The emission factors also depend upon the duty cycle over which the engine was tested. The range in emission factors may be due more to differences in engine test cycle than emissions configuration.

Usage rates for farming equipment in Table 5-8 are combined with fuel production yields in Table 5-9. The location of agricultural emissions are based on assumptions in Section 4. Fuel consumption per lb of biomass are based on a study by Oak Ridge National Laboratory (Graham, 1992). This study covers the requirements for farming short rotation woody crops (SRWC). Such crops require annual application of phosphate and potash fertilizer and nitrogen fertilizer on alternate years. The study shows diesel energy as a proxy for petroleum fuels and other energy inputs. Table 5-8 shows the energy component for diesel in greater detail. ARB's off-road emission study (Kreebe, 1992) indicates that 10 percent of agricultural equipment is gasoline-fueled. Energy requirements for biomass hauling are estimated for a truck, with a fuel economy of 5 mpg, hauling 37,000 lb of biomass over a 50 mile round trip. Energy requirements for corn production are based on more specific experience with this crop. The energy requirements per unit of product fuel are based on the process yield considerations in Section 5.2. Emissions for farming equipment and feedstock transportation are converted from the emission factors in Table 5-6 to g/10,000 Btu in the emissions data base. A subsequent step combines these with energy inputs per gallon of fuel product from Table 5-9.

#### **5.1.1.2 Truck Emissions**

Tanker trucks are used to haul fuel for local delivery as well as longer range transportation for fuels that are not locally available. Table 5-10 shows the emissions from heavy-duty trucks. ARB's EMFAC model estimates truck emissions for the average truck load and weight. These

**Table 5-6. Farm equipment emissions**

<b>Equipment Type</b>	<b>1990 Diesel 101-175 hp</b>	<b>2010 CA Diesel</b>	<b>1990 Gasoline 4-stroke 40-100 hp</b>	<b>2010 Gasoline</b>
Energy rate (Btu/bhp-hr)	9350	9350	11,200 <sup>a</sup>	11,200
Fuel consumption (g/bhp-hr)	220	220	244	250
<b>Emissions (g/bhp-hr)</b>				
NO <sub>x</sub>	11	7	3.0	3.0
CO	3.4	3.4	235	235
CO <sub>2</sub>	700	700	758	758
CH <sub>4</sub>	0	0	0	0
NMOG	1.1	1.1	8.25	6.6 <sup>b</sup>
Source code	b11.1	b11.2	b13.1	b13.2
Reactivity code	9950	9950	9951	9974
Evaporative and fueling NMOG (g/gal)	0.05	0.05	12.2	10.4
(g/MMBtu)	0.38	0.38	98	85
Source code	b13.1	b13.1	b14.1	b14.2
Reactivity code	760	760	9995	9795
Year, data source	Kreebe, 1992	Estimate	Kreebe, 1992	Estimate

<sup>a</sup>20 percent increase in energy consumption with gasoline.

<sup>b</sup>20 percent reduction in mass emissions with RFG.

**Table 5-7. AP-42 emission factors for farm equipment**

<b>Fuel</b>	<b>Diesel</b>	<b>Diesel</b>	<b>Gasoline</b>	<b>Gasoline</b>
<b>Type of Equipment</b>	<b>Tractor</b>	<b>Non-tractor</b>	<b>Tractor</b>	<b>Non-tractor</b>
<b>Emissions (g/bhp-hr)</b>				
NO <sub>x</sub>	9.39	9.03	6.62	5.24
CO	3.34	4.08	143	218
HC	1.70	1.68	6.59	8.62

**Table 5-8. Energy input for farming<sup>a</sup>**

Energy Input	Current Technology		Future technology	
	Per Hectare <sup>b</sup>	Btu/lb Biomass	Per Hectare <sup>b</sup>	Btu/lb Biomass
Diesel	270 L	322	401 L	322
Gasoline equipment	— <sup>c</sup>	36	—	36
Natural gas	77 m <sup>3</sup>	113	77 m <sup>3</sup>	69
Electricity	84 kWh	0.0034 <sup>d</sup>	84 kWh	0.0021 <sup>d</sup>
Diesel Transport	— <sup>c</sup>	37	—	37
Biomass yield (tons/hectare)	12.4		20.4	

<sup>a</sup>Graham, 1992.

<sup>b</sup>Units are shown below.

<sup>c</sup>The total liquid fuel input per hectare is 270 and 410 L. The split between gasoline and diesel is estimated on a Btu/lb basis from Kreebe, 1992.

<sup>d</sup>kWh/lb.

**Table 5-9. Equipment energy use for biomass and coal production**

Fuel/Feedstock	Yield <sup>-1</sup> (lb/gal)	Scenario	Energy Consumption (Btu/gal)			Location
			Diesel Tractor	Gasoline Equipment	Diesel Truck	
Methanol/SRWC <sup>a</sup>	15	1	4830	540	555	CA
Methanol/SRWC	12.2	2,3,4	3928	439	451	CA
Methanol/coal	8.1	1,2,3,4	1440	0	4885	US
Ethanol/waste	15	1	0	0	0	So Cal
Ethanol/corn	19.4	2	6480	2840	1600	Illinois
Ethanol/SRWC	21.6	3,4	6955	778	799	CA
Hydrogen/SRWC	9.6 <sup>b</sup>	3,4	3091 <sup>b</sup>	346 <sup>b</sup>	355 <sup>b</sup>	CA
Production Phase	—	—	1, farming		2, transport	—

<sup>a</sup>SRWC=short rotation woody crop.

<sup>b</sup>lb biomass per lb of hydrogen or Btu per lb of hydrogen.

**Table 5-10. Heavy-duty truck emissions**

<b>Truck Type</b>	<b>1993 CA Inventory</b>	<b>2000 CA Inventory</b>	<b>1990 75,000 GVW</b>	<b>2010 75,000 GVW</b>
Fuel economy (mi/gal) (Btu/mi)	— —	— —	5.0 27,560	5.0 27,560
<b>Emissions (g/mi)</b>				
NO <sub>x</sub>	12.56	12.27	23.5	9.4
CO	12.64	12.17	11.0	11.0
CO <sub>2</sub>	—	—	2000	2000
CH <sub>4</sub>	—	—	0	—
NMOG	2.48	2.58	1.7	1.7
Source code	—	—	73.1	73.2
Reactivity code	—	—	9950	9950
Data source	EMFAC	EMFAC	LACMTA data, adjusted for load (Wool, 1995)	

estimates are based on engine dynamometer results in g/bhp-hr which are converted to g/mi. The conversion factor implicitly takes into account driving patterns and vehicle loads which probably do not reflect those of tanker trucks. The Los Angeles County Metropolitan Transportation Authority has tested numerous heavy-duty vehicles on a chassis dynamometer. A series of tests was run on a truck whose emissions were tested at gross vehicle weights (GVW) ranging from 25,000 to 55,000 lb (Acurex Environmental, 1996). Tank truck emissions are based on these chassis dynamometer tests. More stringent emission controls should result in lower NO<sub>x</sub> emissions for heavy-duty trucks. The 1990 NO<sub>x</sub> estimate corresponds to an engine which emits 5 g/bhp-hr. Browning, 1993 projects that heavy-duty engines meeting a 2 g/bhp-hr standard will be feasible. Current alternative-fueled buses (with 2 g NO<sub>x</sub>/bhp-hr engines) already have NO<sub>x</sub> emissions close to 10 g/mi. The ARB and EPA are working together to develop a national 2 g/bhp-hr NO<sub>x</sub> standard for heavy-duty vehicles. This standard is expected to take effect in 2004. Therefore, year 2010 NO<sub>x</sub> for all trucks in the U.S. are projected to be 40 percent of current levels.

Table 5-11 shows the load carrying capacity of tanker trucks. The gallon carrying capacity depends on the liquid fuel density since the truck must meet axle weight requirements. The values shown in the table are typical for current fuel deliveries. The loads shown in the table are based on the same capacity for alcohol blends and assume that the load will not be varied to take into account small differences in fuel density. The load carrying capacity for gaseous hydrogen is also shown. The load capacity for gaseous hydrogen is so much lower than that of liquid hydrogen, it was not considered further.

Table 5-12 shows the distances for hauling fuels by tanker truck with the assumption of a central Los Angeles fueling location. The distances are based on a typical round trip to the appropriate fuel storage site. Petroleum fuels are stored in proximity to oil refineries in the South

**Table 5-11. Tank truck load for local distribution**

<b>Fuel</b>	<b>Truckload (gal)</b>	<b>Fuel Density (lb/gal)</b>	<b>Fuel Weight (lb)</b>	<b>Truckload Energy (10<sup>6</sup> Btu LHV)</b>
Gasoline	8,500	6.0	51,000	979
Reformulated gasoline	8,500	6.0	51,000	923
Diesel	7,080	7.2	51,000	923
M85	7,800	6.5	50,700	507
E85	7,800	6.5	50,700	638
M100	7,800	6.6	51,500	445
E100	7,800	6.6	51,500	594
LPG	10,000	4.2	42,000	836
LNG	11,000	3.5	42,000	874
LH <sub>2</sub>	11,000	0.584	7,000	361
Hydrogen (2,400 psi)	130,000 <sup>a</sup>	0.53 <sup>b</sup>	688	35.5

<sup>a</sup>Value expressed in scf, not gallons.

<sup>b</sup>Value expressed in lb/100 scf, not lb/gal.

**Table 5-12. Tank truck and pipeline distance for fuel distribution**

<b>Fuel</b>	<b>Application</b>	<b>Round Trip Distance (mi)</b>	<b>Location</b>
Gasoline	Local Delivery	50	S. Coast Air Basin
RFG	Local delivery	50	S. Coast Air Basin
Diesel	Local delivery	50	S. Coast Air Basin
M85	Local delivery	50	S. Coast Air Basin
E85	Local delivery	100 50	Scenario 1 S. Coast Air Basin Scenario 2-4 S. Coast Air Basin
E100 (biomass)	Transport to S. Coast Air Basin	400	Pipeline to LA
M100 (biomass)	Transport to S. Coast Air Basin Local delivery	400 50	Sacramento pipeline S. Coast Air Basin
LPG	Local delivery	50	S. Coast Air Basin
LNG	Transport to S. Coast Air Basin	2000	Wyoming to LA
Scenario 1	Local Delivery	50	S. Coast Air Basin
LNG	Transport to	50	Bakersfield to LA
Scenarios 2,3,4	Local Delivery	50	S. Coast Air Basin
LH <sub>2</sub>	Transport to S. Coast Air Basin	800	Sacramento to LA
Scenarios 2,3,4	Local Delivery	50	S. Coast Air Basin

Coast Air Basin with many storage terminals along the coast (Wilmington, El Segundo, etc.). Methanol is currently stored at a chemical terminal in San Pedro. Some finished fuels are trucked further distances. Ethanol is currently produced near Riverside, California and a longer distribution distance to central Los Angeles is considered for Scenario 1. Future biomass derived fuels may also be trucked into Los Angeles from outside the area. The distance in the South Coast Air Basin for California biomass derived fuels as well as imported LNG are estimated for the freeway distance in the South Coast Air Basin to central Los Angeles.

### 5.1.1.3 Locomotive Emissions

Several fuels and feedstocks are transported by rail. Table 5-13 shows the emissions of locomotive engines. Information from an ARB study on locomotive emissions was used as the basis for current locomotive emissions. Improvements in timing control are expected to reduce  $\text{NO}_x$  emissions while LNG-fueled locomotives can reduce  $\text{NO}_x$  further. While there is significant interest in LNG-fueled locomotives, their market penetration is uncertain. LNG-fueled locomotives were assumed for Scenarios 3 and 4. If LNG is used as a locomotive fuel, it may well be used for trips across the U.S. and not in California alone. The fuel consumption for locomotives is reported in gal/1000 ton-mi. This represents the amount of fuel used for a round trip of cargo hauling. Fuel consumption for LNG locomotives was calculated from the estimated energy use rate in Btu/bhp-hr.

Table 5-14 shows the distance assumptions for locomotive transport for ethanol produced from corn. Most fuel options that involved train transport were eliminated from the study since this transport option was considered to be too expensive. The options that were considered unlikely to occur included the following:

- LNG from Algeria by way of Port Arthur, Texas
- Methanol from coal gasification with coal shipped from Utah

**Table 5-13. Locomotive train emissions**

Locomotive Type	Diesel	Diesel	Advanced Diesel	LNG
Energy rate (Btu/bhp-hr)	—	9167	9200	9723
Fuel Consumption (g/bhp-hr)	—	215.6	216.4	191
(gal/1000 net ton-mi)	—	5.8	5.82	10.5
(hp-hr/1000 ton-mi)	—	87.2	87.2	87.2
<b>Emissions (g/bhp-hr)</b>				
$\text{NO}_x$	9.5	11.3	7	3
CO	3.3	1.3	1.3	1.3
$\text{CO}_2$	—	687	687	516
$\text{CH}_4$	—	0	0	0.6
NMOG	2.2	0.8	0.8	0.2
Source code	—	c23.1	c23.2	c23.3
Reactivity code	—	9950	9950	1001
Year, data source	1973, AP-42	1990, AAR	2010 Scenario 2	2010 Scenarios 3,4

**Table 5-14. Energy use for locomotive transport**

Fuel/Feedstock	Scenario	Distance (mi) <sup>a</sup>	Capacity (gal/net ton)	Route
Ethanol	2	3800	300	Illinois

<sup>a</sup>For all fuels, 50 miles in the South Coast Air Basin, and 50 miles in California were assumed.

#### 5.1.1.4 Marine Vessel Emissions

Crude oil and finished fuels are shipped in tanker ships. Tankers are powered by steam turbines as well as low speed diesels. The most prominent propulsion system for ocean going tankers is a two-stroke diesel (Burghardt).

Table 5-15 shows emissions from typical marine diesel propulsion engines. The NO<sub>x</sub> emissions are comparable to or slightly higher than those from uncontrolled truck engines. Fuel consumption in g/bhp-hr is quite high. One reason for the higher fuel consumption is the higher calorific value of the heavy fuel oil used in marine diesels combined with combustion advantages of low speed operation and higher compression ratios. Fuel consumption of marine diesels has dropped from 140 down to 120 g/bhp-hr over the past two decades (compared to 215 g/bhp-hr for a diesel engine on the EPA transient cycle). NO<sub>x</sub> levels depend on engine load over the ships operating profile. Emission factors that take into account a ships operating profile and are expressed in g/kg fuel shown in Table 5-16.

Tanker capacity is measured in dead weight tons (DWT) which includes the total carrying capacity of the ship. The load efficiency indicates what fraction of the total cargo capacity is actually

**Table 5-15. Emissions from marine diesel engines**

Emission Source	Two-stroke Diesel, Bunker Fuel	Four-stroke Diesel, Bunker Fuel
Energy rate (Btu/bhp-hr)	5890	6086
BSFC (g/bhp-hr)	120 to 140	120 to 140
Emissions (g/bhp-hr)		
NO <sub>x</sub>	13.4	10.4
CO	0.15	0.75
CO <sub>2</sub>	448	463
CH <sub>4</sub>	—	—
NMOG	0.6	0.2
Source	Alexanderson	Alexanderson

**Table 5-16. Emission and use factors for tanker ship operations**

<b>Emission Source</b>	<b>150,000 DWT tanker 1990 diesel motor</b>
<b>At sea use factors</b>	
Fuel Consumption (kg/ton-mi)	0.0018
Load efficiency	0.95
Fuel	Bunker fuel
Energy Content (Btu/kg)	40,350
<b>At sea emissions (g/kg fuel)</b>	
NO <sub>x</sub>	70
CO	1
CO <sub>2</sub>	3300
CH <sub>4</sub>	—
NMOG	4
Sources	Kimble, Melhus, Bremnes
<b>Emission Source</b>	<b>Tug boats and ships</b>
<b>In port use factors</b>	
Port transit time (h)	2
Hotelling, pumping (h)	30
Tugboat operation (h)	8
Fuel use (kg/visit)	7,716
(kg/DWT)	0.051
Fuel	diesel
Energy content (Btu/kg)	42,560
<b>In port and tugboat emission factors (g/kg fuel)</b>	
NO <sub>x</sub>	37
CO	13.9
CO <sub>2</sub>	3200
CH <sub>4</sub>	—
NMOG	6.9
Sources	AP-42, Kelley, Kimble

carried. Fuel consumption decreases with larger tanker size. Tanker carrying load is measured in ton-miles. For marine applications distance is measured in nautical miles (2000 yards) and speed is measured in knots or nautical miles per hour. For this analysis, crude oil, LNG, and methanol are shipped in 150,000 DWT tankers. Fuel consumption for tankers also varies with tanker speed and ocean conditions. Data from several sources (ARB, 1990) indicate that the fuel consumption for a modern tanker is about 1.8 kg/1000 ton-mi. This fuel consumption is based on a round trip, carrying ballast on the return trip.

Tanker ships also produce emissions while in port. Auxiliary engines operate to produce electric power and tugboat maneuver the tanker into port or to the oil unloading platform. In-port time for tanker ships is generally as short as possible in order to maximize use of the tanker. In-port operation time and fuel consumption were estimated from information included in and ARB workshop on marine emissions. Tugboat fuel consumption is estimated from hours of tugboat operation and tugboat fuel consumption curves. NO<sub>x</sub> emission factors are lower for port operations than those for at sea operations because the engines operate at lower load, use lighter diesel oil, and a different mix of engines.

Table 5-17 shows the distances traveled by tanker ships. The capacity of the tanker in gallons of product per DWT is also shown. Tankers carry about 95 percent of their weight capacity as cargo with the balance being consumables and ballast. Thus 95 percent of a short ton results in 288 gal of methanol per DWT (2000 lb/ton/6.6 lb/gal × 0.95 capacity). LNG tankers do not carry their entire tonnage capacity as cargo since they are limited by volume carrying capability.

Table 5-18 shows the marine transportation distance assumptions that are inputs for the emissions data base. Distance traveled is expressed as a percentage of 1000 mi. The percentages represent the weighted average of the shipping distance that corresponds to the locations indicated in the table. Tanker travel distance in the South Coast Air Basin is taken to be 26 nautical miles. Several studies have considered the appropriate distance to include for marine vessel inventories (Port

**Table 5-17. Overview of waterway transportation**

Route to Los Angeles	One Way Distance (naut. mi) <sup>a</sup>	Cargo	Capacity (Gallons/DWT)
Vancouver, BC	570 mi in CA	Methanol	288
Valdez, AK	200 mi in CA	Crude Oil	247
Singapore	15,450	Crude Oil	247
Singapore	15,450	Methanol	288
Singapore	15,450	LNG	400 <sup>b</sup>

<sup>a</sup>Nautical Mile = 1.136 mile = 2,000 yards.

<sup>b</sup>LNG capacity would be 543 gal/DWT if ship were not volume limited. Imported LNG may not be a feasible option for vehicle use due to the cost of rail transportation. This option was not included as one of the cases that were studied.

Table 5-18. Summary of marine transport distances

Fuel	Methanol		Crude Oil	
Year	1990	2010	1990	2010
Location	Vancouver	50% Vancouver 50% Singapore	45% Alaska 5% Indonesia	34% Alaska 24% Indonesia
<b>Mileage Allocation</b> % of 1,000 mi				
South Coast Air Basin	2.6	2.6 <sup>a</sup>	2.6	2.6
California	54.4	27.2	18	12
U.S.	43	21.5	2.3	1.5
ROW	0	771	311	750
<b>Source Code</b>				
Ship	M51.1	M51.1	o21.4	o21.4
Port	M51.3	M51.3	o21.3	o21.3

<sup>a</sup>Represents percentage of 10,000 miles and therefore does not add to 100%.

of Los Angeles). The SCAQMD boundaries include a 32 nautical mile section towards Ventura County and an 18 nautical miles section heading to the South. Other studies have drawn a 88 nautical mile radius from shore or a similar shape out past San Clemente Island. Tanker ships probably reduce their power and coast when entering port which would lead to lower emissions along the coast. A relatively shorter (26 mi) tanker travel distance was assumed for this study while tanker emissions are not adjusted for reduced load. Assuming a longer distance and lower emissions would yield a similar result.

### 5.1.2 Combustion Emissions

Several combustion sources are used in the production of fuels. These include boilers that produce steam for oil refineries, electric power generation, and ethanol distillation. Other combustion energy requirements are reformer furnaces for oil refineries, methanol, hydrogen, and ammonia plants.

Table 5-19 shows the NO<sub>x</sub> emission assumptions for different regions and timeframes. Outside the U.S. (ROW and 1990 U.S. emissions are assumed to be the AP-42 values. NO<sub>x</sub> emissions are projected for other regions and the year 2010 for emission sources that are relevant to scenarios in this study. Combustion sources in the U.S. are assumed to comply with NSPS levels by 2010. California sources are assumed to be equipped with NO<sub>x</sub> controls except for SCR in 1990 and with SCR by 2010. NO<sub>x</sub> emissions from gas fired process heaters in the South Coast Air Basin (other than power generation equipment and prime movers) were assumed to be 0.03 lb/MMBtu. CO, CH<sub>4</sub>, and NMOG emissions were assumed to be the same as those from AP-42. CO<sub>2</sub> emissions reflect the combustion of incremental carbon that was not recently removed from the atmosphere. CO<sub>2</sub> emissions from biomass combustion were counted as zero since the carbon in biomass was recently removed from the atmosphere as CO<sub>2</sub>.

Table 5-19. External combustion — industrial boiler and refinery heater emissions

Emission Source		Industrial Boilers and Refinery Heaters						
Fuel		Residual Oil No. 6	Diesel No. 2	Crude Oil	Coal	Biomass Boiler	Natural Gas	Propane
<b>Emissions (lb/MMBtu)</b>								
NO <sub>x</sub>		0.46 (0.2 to 0.8) <sup>a</sup>	0.138 (0.08 to 0.25)	0.4 (0.3 to 7.52)	0.5 (0.11 to 0.81)	0.12	0.1 (0.03 to 0.53)	0.14 (0.05 to 0.6)
CO		0.0337	0.0363	0.0523	0.0826	0.04	0.0338	0.021
CO <sub>2</sub> <sup>b</sup>		181	159	162	202	0	120	138
CH <sub>4</sub>		0.0067	0.004	0.0008	0.002	0.003	0.0002	0.003
NMOG		0.0053	0.0015	0.0018	0.002	0.003	0.0013	0.0055
<b>NO<sub>x</sub> Assumptions</b>								
SC 1990		—	—	—	—	—	0.08	—
SC 2010		0.03	0.03	0.03	—	—	0.03	—
CA 1990		—	—	—	—	—	0.1	—
CA 2010		—	—	—	—	0.03	0.03	—
U.S. 1990 and ROW		—	—	—	—	—	0.2	—
U.S. 2010		—	—	—	0.3	—	0.1	0.14
Reactivity code		9985	9985	9985	9986	1084	9981	9981
Data Source		AP-42 7/93	AP-42 7/93	AP-42 7/93	AP-42 7/93	AP-42 FBC 7/93	AP-42 7/93	AP-42 7/93

<sup>a</sup>( ) = Range.

<sup>b</sup>Based on values presented in Table 2-1.

Table 5-20 shows combustion energy requirements for fuel production. Oil production and refining and gasification systems are covered separately. Electricity inputs for fuel production are shown for completeness. Emissions from ammonia, methanol, and hydrogen production correspond to combustion energy from a reformer and represent about 30 percent of the total natural gas energy input. Negative values under the heading of production electricity represent net electric power that is produced as part of the fuel production process. The production emissions are credited for the emissions required to produce electricity.

Combustion energy inputs are combined with emission factors in subsequent sections and calculated as g/10,000 Btu. The energy input for biomass production represents the fraction of combustion emissions associated with a gallon of fuel production. For example, 1,400 Btus of LPG are required to produce a gallon of ethanol. This energy is represented as 14 percent of the emission rate for LPG combustion emissions ( $0.14 \times 0.64 \text{ g NO}_x/10,000 \text{ Btu}$ ).

**Table 5-20. Combustion energy inputs**

Fuel/Feedstock	Scenario	Extraction			Production		Location
		Ammonia Production (Btu)	NG/LPG (Btu)	Electric (kWh)	Combustion (Btu)	Electric (kWh) <sup>a</sup>	
Methanol/SRWC <sup>b,c</sup>	1	1000	0	0.05	Gasifier <sup>d</sup>	0.77	CA
Methanol/SRWC	2,3,4	1000	0	0.026	Gasifier	1.07	CA
Methanol/NG-SR	1	0	0	0	32,190	-0.04	ROW
Methanol/NG-SR	2,3,4	0	0	0	30,060	-0.09	ROW
Methanol/NG-POX	2,3,4	0	0	0	POX <sup>d</sup>	0.025	ROW
Ethanol/waste <sup>b</sup>	1	0	0	0.05	41,000	0	S. Coast
Ethanol/corn	2	6,000	1400	0.065	35,000	-1.5	Air Basin
Ethanol/SRWC	3,4	2,000	0	0.045	36,350	-1.8	Illinois
Hydrogen/NG <sup>e</sup>	1	1000	0	0.02	Gasifier <sup>d</sup>	0	CA
Hydrogen/SRWC	2,3,4	1000	0	0		2.18	CA
LPG from natural gas processing <sup>b</sup>	1,2,3,4	0	50	0	0	0	Texas

<sup>a</sup>Net electric production. Some processes generate steam to generate electricity as a byproduct. Byproduct electricity is credited towards the total fuel-cycle emissions.

<sup>b</sup>Per gal or methanol, ethanol, or LPG.

<sup>c</sup>SRWC=Short rotation woody crops.

<sup>d</sup>Gasifiers and partial oxidation reactors (POX) do not burn air, so no combustion occurs in the conventional sense. Emissions are not proportional to the amount of combusted fuel. Emissions are estimated separately.

<sup>e</sup>Per lb of hydrogen.

## **5.2 FUEL PROCESSING**

### **5.2.1 Petroleum Fuels**

A number of petroleum products are produced from crude oil. Refineries produce gasoline, diesel, kerosene/jet fuel, LPG, residual oil, asphalt and other products. A variety of co-feedstocks, including natural gas, electricity, hydrocarbons from other refineries, and MTBE and other oxygenates, complicates the analysis of fuel cycle emissions. Different crude oil feedstocks, gasoline specifications, and product mixes also complicates the picture for refineries.

Determining the emissions from the production of petroleum products involved the following approach. The SCAQMD emissions inventory includes emissions from oil production, refining, and distribution. These emissions are broken down by type, e.g. fugitives from valves and flanges. Emissions from base year, 1990, is based on emission use fees from stationary sources. These values were the basis for determining emissions, on a gram per total amount of petroleum production basis. However, these emissions need to be allocated to the various refinery products in order to reflect the energy requirements for producing different fuels.

A refinery model was used to determine the energy inputs required to produce different gasoline, diesel, and other petroleum products. Refinery combustion emissions were allocated to gasoline in proportion to the energy requirements for refinery units. The refinery model was also used to determine changes in refinery energy needed to produce reformulated gasoline. This approach results in the average emissions from refineries. Displacing gasoline with alternative fuels will have varying effects on gasoline production emissions depending upon the amount of gasoline displaced. The issue of incremental emissions is addressed in Section 5.5.

#### **5.2.1.1 Refinery Model**

A model refinery developed by MARTECH International was used to evaluate the emissions from refinery units. This model was used to allocate emissions to refinery products in this study and to estimate changes in refinery energy consumption for reformulated gasoline production. A generic refinery plan in Figure 5-1 identifies major process units and throughputs for the production of gasoline. The plan includes the following processes:

- Atmospheric crude distillation
- Vacuum crude distillation
- Saturated gas plant
- Naphtha desulfurization
- Catalytic Naphtha reforming
- Kerosene hydrodesulfurization
- Diesel hydrodesulfurization
- Light vacuum gasoil hydrocracking
- Heavy vacuum gasoil desulfurization
- Fluid catalytic cracking
- Unsaturated gas plant
- Sulfuric acid alkylation
- Delayed coking



- Hydrogen manufacture
- Sulfur recovery

The processes included in the plan are representative of those present in most of the major refineries currently operating in the Los Angeles Basin. The objective of the plan is to evaluate emission. No attempt has been made to compare this plan with alternative plans on an economic basis.

#### **5.2.1.2 Crude Feedstock**

Feed to the refinery is 120,000 bbl/d of mixed crudes. The mixture is 30.6° API and contains 2.51 wt% sulfur. This particular mixture was selected primarily because of the availability of crude assay data, and the availability of product yield and quality data for the conversion processes included in the plan. In California, refineries fall into four basic categories:

- Topping
- Hydroskimming
- Conversion
- Deep conversion

The refinery model is intended to represent an average refinery and does not illustrate the variation in energy requirements and product mixes that are seen in actual refineries.

#### **5.2.1.3 Processing Scheme**

Hydrogen processing is used extensively in the plant in order to meet product quality requirements. In addition, feed to the FCC is severely hydrotreated in order to meet SO<sub>x</sub> emission regulations in the FCC regenerator flue gas.

The FCC operates in the maximum gasoline mode. The C<sub>3</sub>/C<sub>4</sub> olefin stream is fed to a Sulfuric Acid alkylation unit. Purchase of outside isobutane is required to meet alkylation requirements.

Feed to the catalytic reformer is primarily a mixture of hydrotreated straight run and coker naphthas plus heavy hydrocracker naphtha. Insufficient hydrogen is produced in the reformer to meet all of the hydrotreating requirements. Additional hydrogen is manufactured in a steam methane reforming unit followed by a pressure swing absorption (PSA) unit.

#### **5.2.1.4 Product Yields and Quantities**

The yields and quantities from the products from the various processes were taken primarily from licensor information. Generalized correlations were used when licensor data were unavailable. Table 5-21 represents the total capacities of the processes used in all California refineries as of January 1, 1991. The refining scheme represents the mix of most California refining operations; however, it does not closely match catalytic cracking, catalytic hydrofining, and isomerization. The model was developed under the constraints of meeting octane, benzene, RVP, olefin, and oxygen objectives. Then, changes in energy input, natural gas import, and MTBE import were determined. Given the need to meet fuel properties while also maintaining the constraints of the model, some

**Table 5-21. Comparison between California 1991 refinery capacities and model refinery (92096-E-1)**

Stream	California		Flow Diagram 92096-E-1	
	bbl/day	vol %	bbl/day	vol %
Crude	2,339,200	100	120,000	100
Vacuum distillation	1,334,630	57	61,080	51
Thermal	538,000	23	31,019	26
Cat cracking	656,000	28	14,767	12
Cat reforming	545,500	23	29,406	25
Cat hydrocracking	413,000	18	21,532	18
Cat hydrofining	573,500	25	41,401	35
Cat hydrotreating	937,900	40	40,556	34
Alkylation	132,500	6	6,032	5
Isomerization	17,900	1	10,973	9
Lubes	29,400	1	—	—
Asphalt	89,500	4	—	—
Hydrogen manufacturer (Mscf/day)	1053	—	50	—
(scf/bbl crude)	—	450	—	415
Coke ton/day	20,962	—	1460	—
ton/day/1000 bbl	—	9	—	12

compromises in outputs had to be made. Within the constraints of the model, reducing RVP was very difficult and the RFG model has very low butane content. It is not clear if a single refinery model could be made to represent all of California's refineries. Therefore, these results should simply be used as a tool for evaluating the changes in energy inputs when converting to reformulated gasoline production.

This discrepancy between the model and California refinery components is probably not significant within the objectives of the model. Figure 5-2 shows the mix of refinery products in California (CEC, 1990). The mix of gasoline, distillate products, and LPG is quite close to when comparing Figures 5-1 and 5-2. The plant uses natural gas feed for hydrogen manufacturing. Table 5-22 shows the emissions from the units of the model oil refinery. Total combustion  $\text{NO}_x$  emissions based on 0.03 lb/MMBtu translate into 0.18 g/gal of gasoline (total emissions divided by gasoline output). This value compares to 0.289 g/gal in the 1990 SCAQMD inventory.

The refinery modeling was used to allocate combustion emissions to gasoline. Emissions from refinery units in the model were allocated to the petroleum products produced by each refinery unit. For example, all of the combustion emissions associated with the diesel hydrodesulfurization

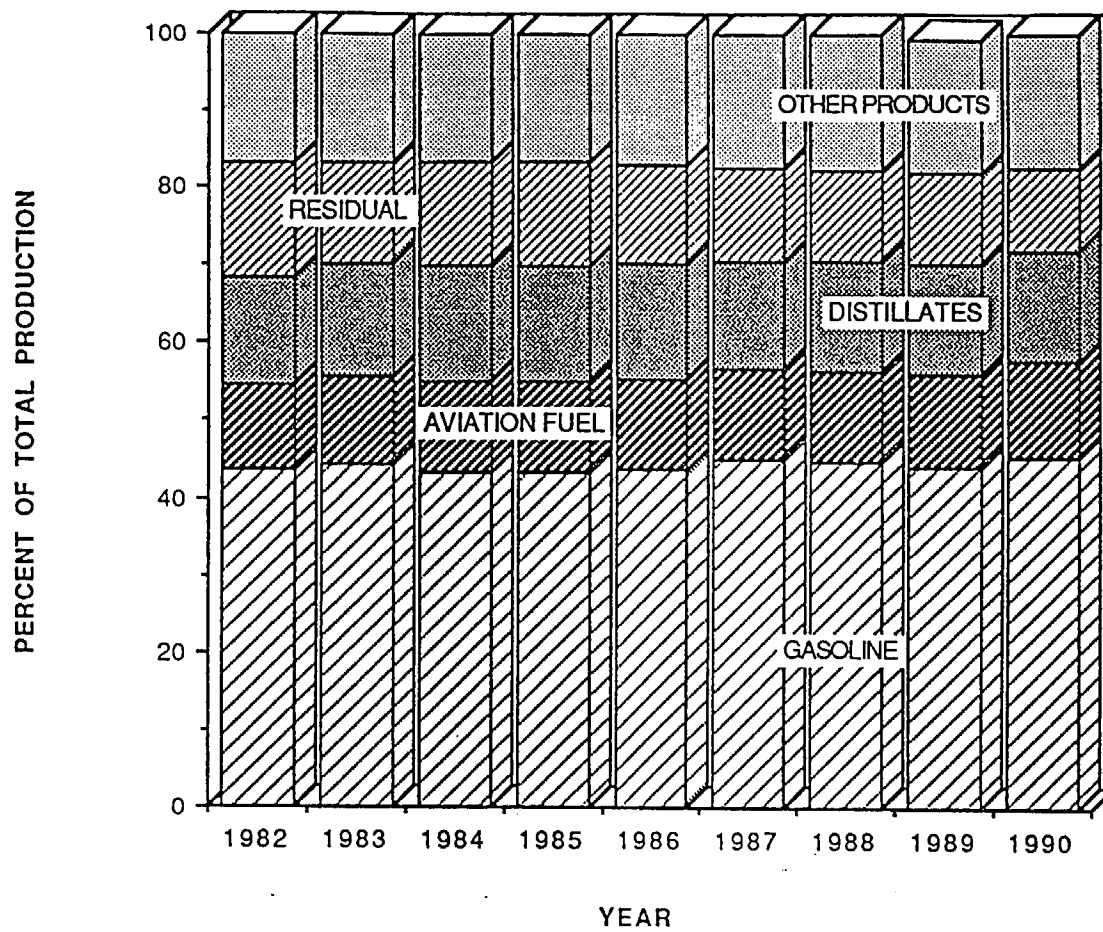


Figure 5-2. California refinery product distribution (CEC, 1990)

**Table 5-22. Petroleum refinery emissions by fuel input**

Unit, Capacity	MMBtu/day	Emissions (lb/hr)		
		NO <sub>x</sub>	CO <sub>2</sub>	SO <sub>2</sub>
<b>Fired refinery units</b>				
Crude, 120,000 bbl/day <sup>a</sup>	8,976	11.22	56,212	28.1
Delayed coker, 30,400 bbl/day	4,608	5.76	28,857	14.43
FCC feed HDS, 16,150 bbl/day	888	1.11	5,547	2.77
Hydrocracker, 21,500 bbl/day	3,288	4.11	20,580	10.29
Diesel HDS, 19,900 bbl/day	528	0.66	3,294	1.65
Kerosene HDS, 18,040 bbl/day	1,560	1.95	9,758	4.86
Naphtha HDS, 29,400 bbl/day	1,944	2.43	12,155	6.08
Reformer, 29,400 bbl/day	7,992	9.99	50,041	25.02
Hydrogen unit, 40 MMscf/day	4,712	5.89	16,680	—
Sulfur recovery, 290 tons/day	840	1.05	5,254	49.0
<b>Steam import to refinery</b>				
672 MMBtu/day				

<sup>a</sup>bbl = barrel, 42 gal.

<sup>b</sup>Emission factors are 0.03 lb NO<sub>x</sub>/MMBtu, 150 lb CO<sub>2</sub>/MMBtu, and 0.075 lb SO<sub>2</sub>/MMBtu. FCC emissions are not included. Estimate 7.0 lb/hr from SCAQMD 1990 inventory.

Note: (A) Purchased IsoC4 = 1,333 barrels/day  
 (B) Purchase Natural Gas = 398 barrels/day  
 (C) Purchased Electricity = 45,300 kW

unit are attributed to diesel fuel. Table 5-23 shows the allocation of crude oil energy input and imported energy to gasoline, diesel, kerosene (same as jet fuel), and LPG.

Fugitive emissions and oil production emissions were allocated to gasoline in proportion to gasoline's share of the mix of petroleum products in California (Figure 5-2).

### 5.2.1.5 Reformulated Gasoline

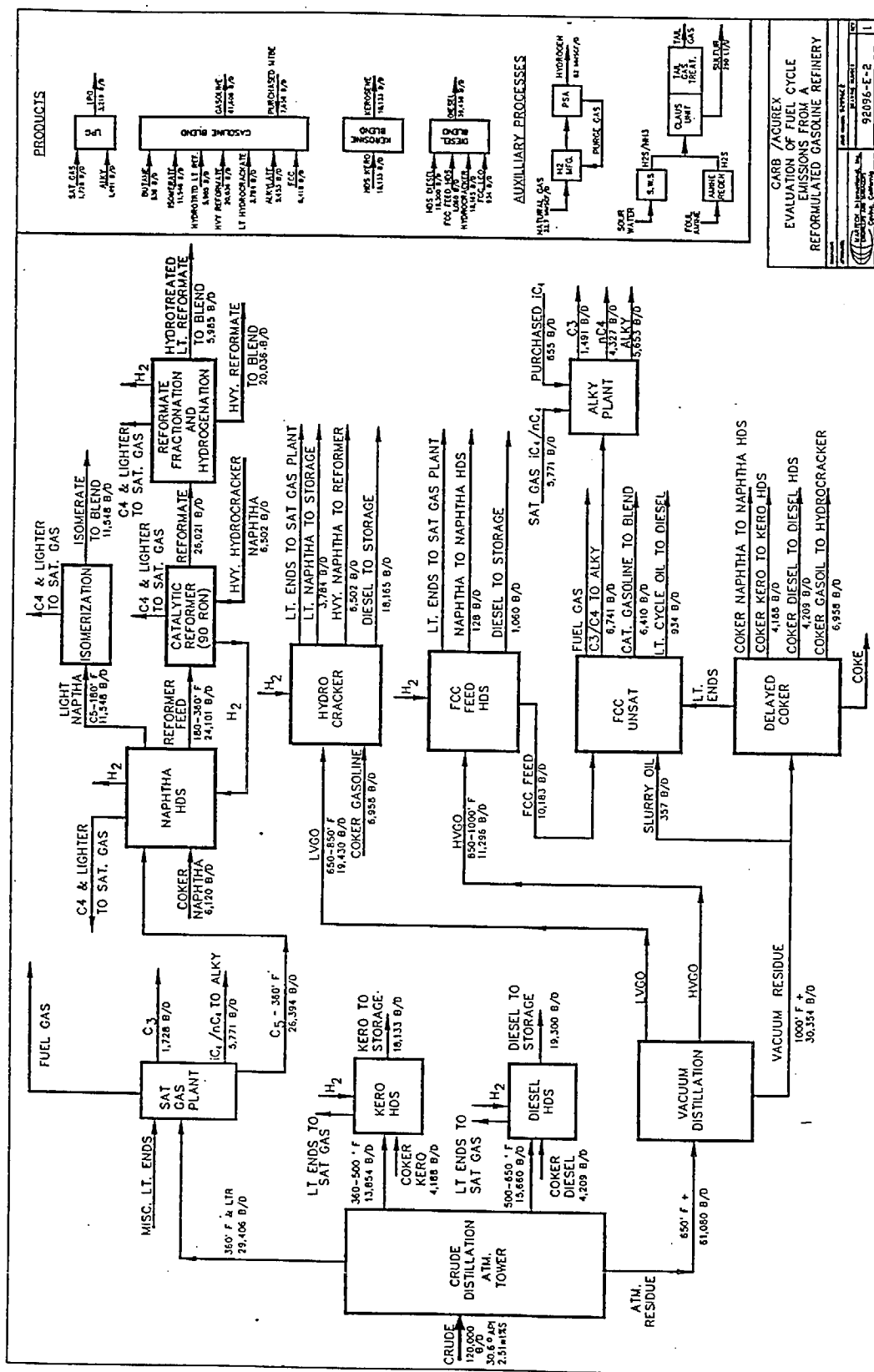
The refinery model was adjusted for the production of Phase 2 gasoline (Figure 5-3). This study assumed that the refinery imported 6730 barrels of MTBE to blend with the gasoline. In addition, additional hydrotreating was required to provide lower sulfur levels in gasoline. Emissions associated with isobutylene production were assumed to be similar to those for gasoline production and were included in the refinery model. Fuel-cycle emissions from natural gas, electricity, and methanol production were included as part of the fuel production emissions and were tracked separately.

Table 5-24 compares the output from the model refinery producing conventional gasoline and the model refinery producing reformulated gasoline. The refinery product outputs were combined with energy inputs to determine the allocation of combustion emissions and feedstocks to reformulated gasoline in Table 5-23.

**Table 5-23. Allocation of product output and energy consumption for refineries**

Product	Product Output Btus (%)	Combustion Fuel Allocation (%) <sup>a</sup>	Energy Inputs (Btu per gallon of product)			
			Natural Gas	Electricity	Methanol	Total Energy Ratio (%)
<u>Conventional</u>						
Gasoline	56	69	551	2549 (0.75 kWh)	0	119.6
Kerosene (jet)	17	41	348	546 (0.15 kWh)	0	108.7
Diesel	25	48	482	1549 (0.45 kWh)	0	112.9
LPG	2	17	197	64 (0.019 kWh)	0	107.3
<u>Phase 2</u>						
Gasoline	58	69	551	2594 (0.75 kWh)	2633	120.8
Kerosene (jet)	17	42	348	546 (0.15 kWh)	0	108.7
Diesel	23	52	482	1549 (0.45 kWh)	0	112.9
LPG	2	15	197	64 (0.019 kWh)	0	107.3

<sup>a</sup>The combustion energy allocation applies to emissions and energy use expressed on g/gal of gasoline basis and determines the emissions allocated to the specific fuel on a g/gal basis.



**Table 5-24. Comparison between gasoline pools from conventional and reformulated gasoline model refineries**

Component	Refinery "A" Conventional		Refinery "B" Reformulated	
	bbl/day	vol %	bbl/day	vol %
Isomerate	11,548	20.4	11,548	18.72
Reformate (100 RON <sup>a</sup> )	22,664	40.0	—	—
Hydrotreated Lt. Reformate	—	—	5,985	9.7 <sup>b</sup>
Hy Reformate (96 RON)	—	—	20,036	32.6 <sup>b</sup>
Lt. Hydrocrackate	3,087	5.5	3,784	6.1
Alkylate	6,032	10.6	5,653	9.2
MTBE	—	—	7,656	12.4
FCC Gasoline	9,584	16.9	6,410	10.4
Butane	3,764	6.6	536	0.9 <sup>c</sup>
<b>Total</b>	<b>56,679</b>	<b>100.0</b>	<b>61,608</b>	<b>100.0</b>
<b>Estimated Properties</b>				
RVP (psi)	9.5		7.0	
Total Aromatics (vol %)	30		22	
Benzene (vol %)	2		< 1	
Olefins (vol %)	6		4	
T-90 °F	315		315 <sup>d</sup>	
RON	93		94	
MON <sup>e</sup>	85		86	
Oxygen (wt%)	—		2.7 <sup>f</sup>	

<sup>a</sup>RON = Research Octane Number.

<sup>b</sup>These values are somewhat high for Phase 2 reformulated gasoline.

<sup>c</sup>This low level of butane may be difficult to achieve in an existing refinery without extensive revamp of upstream fractionation equipment.

<sup>d</sup>ARB Phase 2 specification is 330°F. Projected value is 290°F.

<sup>e</sup>MON = Motor Octane Number.

<sup>f</sup>ARB Phase 2 limit is 2.7%. Projected value is 2%.

#### 5.2.1.6 SCAQMD Inventory

The SCAQMD emissions inventory provides insight into emissions from oil production, refining, and distribution in the four county South Coast Air Basin. Refineries and oil producers submit emission fee forms annually to the SCAQMD. Emissions for these forms are determined from either published emission factors or from source testing. These values make up SCAQMD's base year inventory.

Most of the emission rates are determined from calculations that depends on equipment type and throughput using SCAQMD and AP-42 emission factors. Other emission are determined from source testing. Testing performed by the API indicates that some of these factors may be excessively

high. WSPA indicates that some of these emission factors are overstated and do not accurately reflect SCAQMD's stringent emission controls that are already in place. However, this subject is still under review by SCAQMD and ARB.

The SCAQMD inventory is determined for average days as well as summer and winter days. The summer inventory was examined in this study since it is intended to represent conditions for maximum ozone formation. The summer inventory may not be representative of the petroleum industry since refineries operate at fairly constant capacity and are not affected by seasonal activities. The summer inventory may also be adjusted for increases in temperature and higher evaporative emissions. Higher RVPs in the winter might cancel out the temperature effect, however, crude oil breathing losses will be higher.

Table 5-25 shows the SCAQMD summer inventory for the years 1990, 2000, and 2010 for the South Coast Air Basin (SCAQMD, April 1994, III-B). All of the values in the table were extracted from the 1994 inventory document with the exception of the refinery product throughput (19,500,000 gal/day) which was determined from a data base run performed by ARB's inventory division. Emissions for 1990 represent a baseline from which future year emissions are projected. The inventory for the years 2000 and 2010 are based on economic growth factors and control factors in the SCAQMD plan (SCAQMD, April 1994, III-A). While the g/gal emissions for the years 2000 and 2010 based on the SCAQMD plan were not used further in this study, they are presented here for comparison. This study assumes no further growth in oil refinery capacity and refinery emissions consistent with a fixed output. The departure from the inventory and the values used in this study could be a significant result. Air quality modelers have expended a substantial effort in evaluating the effect of alternative fueled vehicles on ozone in the South Coast Air Basin (Russell, 1992, Auto Oil, 1994). Assumptions on baseline refinery emissions might be expected to have an effect on the outcome of such models and the implications of Table 5-25 should be examined.

The estimated gasoline production corresponding to the growth factors is used to calculate g/gal values in Table 5-25. Emissions for the years 2000 and 2010 inventories increase due to growth factors for additional gasoline throughput through service stations and also increases in petroleum activities in the South Coast Air Basin. All of the emissions estimates used in this study for the year 2010 are based on reduction factors discussed later.

The SCAQMD inventory for gasoline distribution emissions shown near the bottom of Table 5-25 indicate no reduction of emission factors between the years 1990 and 2010. Reduced vapor pressure due to reformulated gasoline as well as vehicle on-board vapor recovery systems will be phased in over this period. These measures might be expected to reduce both refueling working losses and possibly fuel spillage.

The emission categories in Table 5-25 are organized according to oil production and refining and gasoline storage and distribution. The SCAQMD inventory for gasoline distribution is lumped into a category for gasoline and methanol distribution. However, the volume of methanol in the inventory is either zero or negligible. Gasoline distribution emissions and retail station throughput correspond to published ARB numbers (Asragadoo, 1992). The total tons/day values in Table 5-25, listed by source category, do not completely correspond to the total inventory for petroleum operations (in the year 1990). Total petroleum processing, storage, and transfer VOC emissions for summer operation are reported as 107.3 tons/day VOC, and 1.38 tons/day NO<sub>x</sub> (SCAQMD, 1992).

Table 5-25. SCAQMD inventory for oil production, refining, and marketing

Control name	Control Code	1990 (t/d)		1990 (g/gal)		2000 (t/d)		2000 (g/gal)		2010 (t/d)		2010 (g/gal)	
		ROG	NOx	ROG	NOx	ROG	NOx	ROG	NOx	ROG	NOx	ROG	NOx
<u>Oil Production</u>													
Pipeline Heaters	121	0	0	0.0000	0.0000	0	0	0.0000	0.0000	0	0	0.0000	0.0000
Fuel combustion	--	0.97	1.2	0.0452	0.0559	1.22	0.56	0.0439	0.0202	1.44	0.2	0.0385	0.0053
TEOR Steam Generators	118/126	0	0.06	0.0000	0.0028	0	0.02	0.0000	0.0007	0	0.02	0.0000	0.0005
Pumps & compressors	530	0.28	0	0.0130	0.0000	0.2	0	0.0072	0.0000	0.2	0	0.0053	0.0000
Sumps & pits	534	0.2	0	0.0093	0.0000	0.27	0	0.0097	0.0000	0.27	0	0.0072	0.0000
Marine vessel operation	407	4.58	0	0.2133	0.0000	1.04	0	0.0374	0.0000	1.04	0	0.0278	0.0000
Oil field storage	410	4.58	0	0.2133	0.0000	5.93	0	0.2134	0.0000	5.93	0	0.1584	0.0000
<u>Oil Refining</u>													
Refinery fuel combustion	--	2.56	6.20	0.1192	0.2887	3.21	1.80	0.1155	0.0648	3.55	1.87	0.0948	0.0500
Refinery boilers & heaters	103	0.04	0	0.0019	0.0000	0.06	0	0.0022	0.0000	0.06	0	0.0016	0.0000
Flares	201	0.75	0.66	0.0349	0.0307	0.96	0.79	0.0346	0.0284	0.96	0.79	0.0256	0.0211
Petroleum coke calcining	501	0	0	0.0000	0.0000	0	0	0.0000	0.0000	0	0	0.0000	0.0000
Fluid catalytic cracking	505	0	0.69	0.0000	0.0321	0	0.93	0.0000	0.0335	0	0.93	0.0000	0.0248
Valves & flanges	506	7.78	0	0.3623	0.0000	5.28	0	0.1900	0.0000	5.28	0	0.1411	0.0000
Small relief valves	507	3.73	0	0.1737	0.0000	2.63	0	0.0947	0.0000	2.63	0	0.0703	0.0000
Second, oil/water separators	517	1.94	0	0.0903	0.0000	2.6	0	0.0936	0.0000	2.6	0	0.0695	0.0000
Sewers & drains	523	3.87	0	0.1802	0.0000	5.19	0	0.1868	0.0000	5.19	0	0.1387	0.0000
Pumps & compressors	524	2.56	0	0.1192	0.0000	1.82	0	0.0655	0.0000	1.82	0	0.0486	0.0000
Vacuum systems	526	0.08	0.01	0.0037	0.0005	0.11	0.01	0.0040	0.0004	0.11	0.01	0.0029	0.0003
<u>Gasoline Storage</u>													
Refinery fixed roof tanks	405	2.36	0	0.1099	0.0000	3.17	0	0.1141	0.0000	3.17	0	0.0847	0.0000
Refinery floating roof tanks	406	2.58	0	0.1201	0.0000	3.47	0	0.1249	0.0000	3.47	0	0.0927	0.0000
Bulk storage working loss	401	0.13	0	0.0061	0.0000	0.15	0	0.0054	0.0000	0.15	0	0.0040	0.0000
Tank truck working loss	402	1.06	0	0.0494	0.0000	1.32	0	0.0475	0.0000	1.32	0	0.0353	0.0000
Throughput (1,000 gal/d); Subtotal	--	19,500	19,500	1.865	0.4107	25,229	25,229	1.390	0.1479	33,985	33,985	1.047	0.1021
<u>Gasoline Distribution</u>													
Srv station tank working loss	403	7.10	0	0.3954	0.0000	7.29	0	0.3954	0.0000	7.29	0	0.3954	0.0000
Srv station tank breathing	412/413	1.137	0	0.0633	0.0000	1.19	0	0.0645	0.0000	1.19	0	0.0645	0.0000
Vehicle refueling working loss	404	11.37	0	0.6332	0.0000	11.68	0	0.6335	0.0000	11.68	0	0.6335	0.0000
Vehicle fueling spillage	--	5.71	0	0.3178	0.0000	5.91	0	0.3206	0.0000	5.91	0.0000	0.3206	0.0000
Total production and distribution	--	65.36	8.82	3.2746	0.4107	64.70	4.11	2.8043	0.1479	65.26	3.82	2.4611	0.1021
Throughput (1,000 gal/d)	--	16,304	16,304	--	--	16,740	16,740	--	--	16,740	16,740	--	--

Processing, storage, and transfer NO<sub>x</sub> emissions for 1990 in Table 5-25 are 1.27 tons/day (excluding refinery) which is a small discrepancy with the 1.38 ton/day value. There is a larger difference in ROG emissions (about 50 tons/day in Table 5-25 compared with 107.3 tons/day. This discrepancy may be due to the classification of some emission sources. This larger total petroleum category appears to include natural gas production not included in Table 5-25 based on the large fraction of TOG (about 300 tons/day, which includes methane) that corresponds to the 107.3 tons/day of VOC. Therefore, the values that are presented in Table 5-25 appear to be an appropriate baseline for estimating refinery emissions.

Emission rates in g/gal of gasoline were calculated for the categories in Table 5-25, taking the ton/day emissions divided by throughput. CEC data was used to determine 1993 gasoline production figures for South Coast Air Basin Refineries (CEC, 1993). Gasoline sales at service stations and other dispensing facilities were determined by ARB from fuel tax data. The smaller gasoline sales versus production for the South Coast Air Basin area is consistent with exports to East San Bernadino, Ventura, and San Diego Counties as well as to Arizona and Nevada. Emissions for Scenario 1 were based on the SCAQMD 1990 inventory, while emissions for Scenarios 2, 3, and 4, were based on reduction factors applied to g/gal estimates. Thus, uncertainties in the inventory throughput do not affect the outcome of this study.

Table 5-26 compares the VOC emissions from oil production and distribution from the 1990 SCAQMD inventory to g/gal values presented by DeLuchi and Lyons. The refining and production values in Table 5-25 are shown on a total refinery emissions per gallon of gasoline basis. These emissions must be allocated to gasoline (56 percent for production and 69 percent for refining as shown in Table 5-23. The values by DeLuchi were also allocated to gasoline production.

**Table 5-26. Comparison of VOC emissions from oil production and distribution (g/gal)**

Emission Source	SCAQMD 1990	South Coast Air Basin Table 5-25 Scenario 1	Deluchi, 2000 RUL		Lyons 7.0 RVP
			Low	High	
Oil production	0.4489 <sup>a</sup>	0.277	0.135	0.135	0
Oil refining	0.9294 <sup>a</sup>	0.812	1.05	1.05	0
Refinery product storage	0.230 <sup>a</sup>	0.19	0.168	0.168	Included
Pipeline transfer	Included	0	0.0047	0.23	0
Bulk storage working loss	0.0061	0.0383	0.273	0.553	0.1675
Tank truck fill spillage	0	0.0176	0	0	0.0318
Tank truck working loss	0.049	0.0566	1.276	1.416	0.1317
Service Station working loss	0.395	0.1796	0.163	0.172	0.1675
Service station tank breathing	0.063	0.29	0.348	0.348	0
Vehicle refueling working loss	0.633	0.4123	0.277	0.713	0.1766
Vehicle fueling spillage	0.318	0.318	0.318	0.318	0.3178
Total	3.073	2.59	4.013	5.103	0.993

<sup>a</sup>Total emissions per gallon of gasoline. All other values in this table allocate the share of refinery emissions to gasoline according to guidelines laid out in each study.

### 5.2.1.7 Potential Emission Reductions

The 1990 SCAQMD inventory, expressed in g/gal, was used to determine the emission rates for petroleum operations in the South Coast Air Basin. 1990 emissions for oil production and refineries correspond to the g/gal values in Table 5-25. Emissions for 2010 were estimated by multiplying the 1990 values by reduction factors in the SCAQMD plan.

Table 5-27 shows SCAQMD reduction factors (referred to as control factors, SCAQMD, 1994) that apply to the estimation of future year inventories. Correction factors that take into account lower fugitive emissions are shown on the right column of the table. These reduction factors take into account all emission reduction factors considered in the SCAQMD plan.

Fluidized catalyst crackers (FCC) represent a special case since combustion does not occur in a typical manner. Carbon deposits build up in the FCC and reduce its efficiency. Spent catalyst is sent to a regenerator to burn off the carbon. The carbon is oxidized to form CO and the CO is burned in a boiler. Prior to 1993, emissions from CO boilers were limited to 0.14 lb/MMBtu. After 1993 this limit became 0.03 lb/MMBtu.

Comparing the results of the refinery model to the estimate from the South Coast Air Basin Inventory, the model indicates 0.19 g/gal of direct combustion refinery NO<sub>x</sub> emissions compared with 0.289 g/gal for the 1990 SCAQMD inventory (total NO<sub>x</sub>/total gasoline). The 21 percent factor in Table 5-27 reduces the SCAQMD inventory value for 2010 NO<sub>x</sub> to 0.061 g/gal. The SCAQMD inventory based values were used in this study. The refinery model was used to determine the allocation to gasoline and project emissions from reformulated gasoline production.

Recent studies provide an abundance of data on fugitive emission correlations for refinery and gasoline terminal equipment. A 1993 WSPA/API study covers refinery fugitive emissions and a 1993 API study covers marketing terminals. GRI/API are also studying fugitive emissions from oil and

**Table 5-27. Control factors by SCAQMD for post-1990 compliance**

Rule Adoption Date	No.	Rule Name, Pollutant	Reduction Factor		
			1994	2000	2010
May 1990	431.1	Gaseous Fuel Sulfur Content, SO <sub>x</sub>	0.6	0.17	0.17
Apr. 1990	431.2	Liquid Fuel Sulfur Content, SO <sub>x</sub>	0.16	0.16	0.16
Aug. 1988	1109	Refiner Boiler and Process Heater, NO <sub>x</sub>	0.71	0.21	0.21
Aug. 1990	1110	Emissions from Internal Combustion Engines, NO <sub>x</sub>	0.73	0.36	0.078
July 1991	1142	Marine Tank Vessel Operations, VOC	0.06	0.06	0.06
Oct. 1990	1146	Industrial Boilers, Generators, and Heaters, NO <sub>x</sub>	0.38	0.36	0.36
July 1989	1173	Fugitive Emissions of VOCs, VOC	0.53	0.53	0.53

gas production operations. These studies provide data on the relationship between mass emissions and gas concentrations for fugitive hydrocarbon emissions. The refinery study generated data that indicated lower mass emissions for a given hydrocarbon concentration (correlation factor). These correlation factors are lower than those used for current inventory calculations in the South Coast Air Basin. However, the new emission studies also use different measurement and calculation protocols than those used in inventory calculations. These new fugitive emission data are being evaluated by air quality regulators. WSPA estimates that fugitive emissions are 3 to 10 times lower than currently calculated (WSPA, 1994 Comments on SCAQMD plan). However, the effect of new correlation factors on existing inventory calculations is not certain and has not been evaluated by air quality regulators.

Gasoline production emissions for Scenario 1 correspond to those in the 1990 inventory. Scenarios 2, 3, and 4, are adjusted to reflect emission control rules for the year 2010. The extent of emission controls on oil production in the South Coast Air Basin affects primarily the analysis of average emissions. The emissions from producing a marginal gallon of gasoline are assumed to be zero (based on fuel supply and demand considerations). Therefore, the extent of emission control on refinery emissions does not affect the analysis of marginal emissions in this study.

Comments from the oil industry indicate that the 1990 SCAQMD inventory is overstated by a factor of approximately 5, based on the API refinery study. The study shows lower VOC emissions as a function of measured VOC concentrations than had previously been used for inventory analysis. However, according to ARB, the API study correlates mass emissions as a function of measured concentrations according to a new protocol for measurements. Therefore, it is not clear that applying the methodology in the API study to California refineries would result in a reduction in mass emissions. Consequently, fugitive VOC emissions from refineries were based on the 1990 inventory and reduction factor shown in Table 5-27.

To put the values in Table 5-25 in perspective, the SCAQMD projects a 56 ton/day decrease in  $\text{NO}_x$  emissions from all stationary sources subject to RECLAIM by the year 2010. A further  $\text{NO}_x$  reduction of 19 tons/day (by 2010) is expected from the RECLAIM program as well as further emission controls on stationary internal combustion engines.

### 5.2.2 Methanol

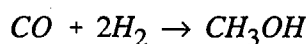
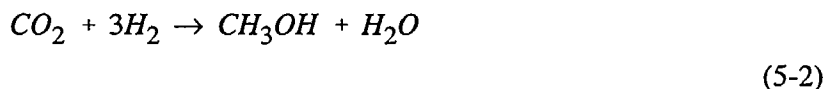
Methanol was first produced by heating wood and distilling the products. In 1913, methanol was produced by passing CO and  $\text{H}_2$  over an iron catalyst. Currently, almost all of the methanol in the world is made by dissociating natural gas, primarily  $\text{CH}_4$ , into CO and  $\text{H}_2$  with the addition of steam or oxygen (referred to as steam reforming or partial oxidation, respectively). Some  $\text{CO}_2$ ,  $\text{CH}_4$ , and light hydrocarbons are also produced. This gas mixture produced through steam reforming or partial oxidation is called synthesis gas or syngas. Methanol is produced under pressure in a reactor by catalyzing CO and  $\text{CO}_2$  with  $\text{H}_2$ . Crude methanol produced by the reactor is then refined into chemical grade methanol.

Steam reforming of natural gas yields synthesis gas for methanol production through the following chemical reaction:



The products that are formed by the gasification of coal or biomass (CO, CO<sub>2</sub>, H<sub>2</sub>, H<sub>2</sub>O and CH<sub>4</sub>) can also be processed into suitable feedstock for methanol synthesis. Likewise, CO<sub>2</sub> and H<sub>2</sub> can be the feedstock for methanol production.

Methanol produced by catalyzing CO and CO<sub>2</sub> with H<sub>2</sub> is formed through the following reactions:



Process energy requirements for methanol production from natural gas, coal, and biomass are shown in Tables 5-28 through 5-30. Emissions were determined from the combustion energy requirements and using EPA emission factors for external combustion equipment. Data from SPECIATE provided fugitive emissions from purge and distillation. Natural gas, coal, and biomass feedstocks for methanol production were considered. These are all thermochemical processes that produce the required mixture of CO and hydrogen at high temperatures. The gas is cooled and reacted to produce methanol.

Figure 5-4 shows the configuration of a natural-gas-to-methanol facility. This facility converts natural gas to synthesis gas in a steam reformer. Emission sources include the reformer flue gas, purge vents, distillation vent, and other fugitive emissions.

The POX process produces a more stoichiometrically optimum synthesis gas which is fed to the methanol reactor. In this process, oxygen reacts with methane to produce two moles of hydrogen per mole of CO. The POX reactor is exothermic and does not require combustion with air. Therefore, NO<sub>x</sub> emissions from this process are negligible. Combining a POX plant with a steam reformer is a particularly advantageous process since the exothermic heat from the POX unit can be used as energy for the steam reformer. When available, adding CO<sub>2</sub> can enhance the efficiency of methanol production.

Natural gas production and transport emissions are similar to those for CNG production. A pipeline distance of 200 miles was assumed for feedstock transport and the same fugitive values as those for CNG were used. Transport emissions take into account the pipeline distance and natural gas feed rate.

Emissions from production facilities were estimated from the SPECIATE data base and emission factors for combustion emissions. Fugitive emissions from 1990s technology are based on values in SPECIATE. These include purge vent and distillation vent emissions. For future technology, 80 percent control is assumed as these hydrocarbons will be burned in the reformer. No data on other fugitive emissions from valves were available, and a total of 50 lb of hydrocarbon

Table 5-28. Methanol processing from natural gas

Process	Steam Reforming						Combined Partial Oxidation			Various
	Current			Advanced						
Fuel Processing	-0.04  66.8  96,970 0.941  32,190			-0.09  68.3  94,840 0.921  30,060			0.25  72.3  89,591 0.870  24,820			—  62 to 77  83,800 to 104,000  19,260 to 39,500
Electricity use (kWh/gal)										
Energy ratio (%)										
NG <sup>a</sup> feed (Btu/gal) (100 scf/gal)										
Combustion (Btu/gal)										
Emission Source	P.V. <sup>b</sup>	D.V. <sup>c</sup>	Reformer	P.V.	D.V.	Reformer	P.V.	D.V.	Vent	—
Emissions (g/gal)										—
NO <sub>x</sub>	0	0	2.94	0	0	1.36	0	0	0.28	—
N <sub>2</sub> O	0	0	0	0	0	0	0	0	0	—
CO	0	0	0.50	0	0	0.46	0	1	0.09	—
CO <sub>2</sub>	5	1	1,135	1	1	1,023	1	1	737	—
CH <sub>4</sub>	2.9	0	0.04	0.29	0	0.04	0.29	0	0.01	—
NMOG <sup>d</sup>	0.4	1.2	0.04	0.04	0.12	0.04	0.04	0.12	0.01	—
Profile	1070	1071	9981	1070	1071	9981	1070	1071	9981	—
Reference	Unnasch, 1989			Bechtel			Bechtel			DeLuchi

<sup>a</sup>NG = Natural gas.

<sup>b</sup>P.V. = Purge vent.

<sup>c</sup>D.V. = Distill vent.

<sup>d</sup>NMOG = Non-methane organic gases.

**Table 5-29. Methanol processing from coal and sewage sludge**

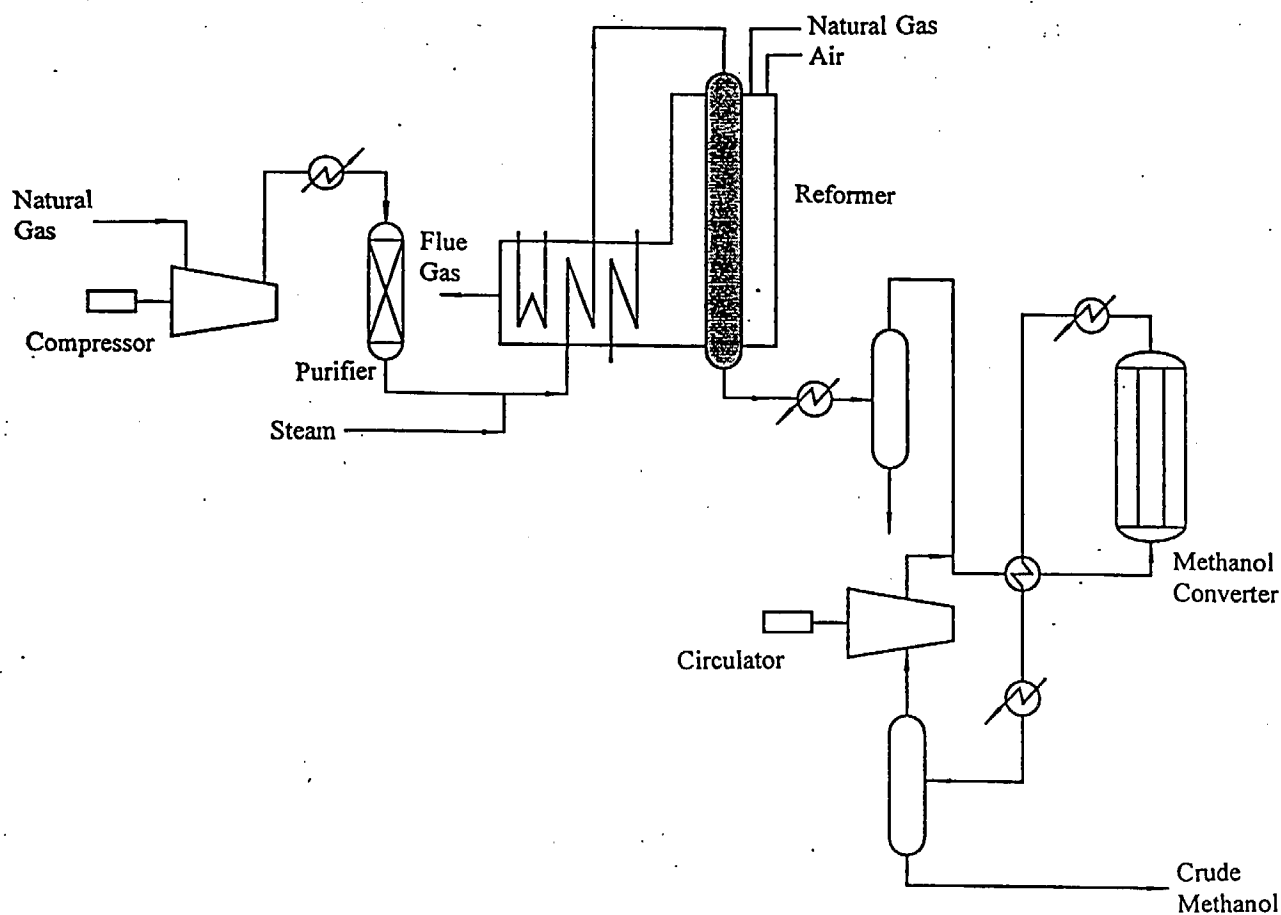
<b>Process</b>	<b>Shell Entrained Bed Oxygen-Blown</b>		<b>Entrained Bed Oxygen-Blown</b>	
<b>Fuel Processing</b>				
Electricity				
Use (kWh/gal)	2.20		0.02	
Production (kWh/gal)	0.29		—	
Energy ratio (%)	75.6		56.2	
Coal feed (Btu/gal)	80,820		114,700	
Sludge feed (Btu/gal)	0		0	
Net combustion (Btu/gal)	3,003		23,694	
<b>Emission Source</b>	<b>Vent</b>	<b>Purge Gas Combustion</b>	<b>Vent</b>	<b>Purge Gas Combustion</b>
<b>Emissions (g/gal)</b>				
NO <sub>x</sub>	0	0.14	0	1.1
CO	0	0.05	12.2	0.36
CO <sub>2</sub>	722	104	16,580	5,740
CH <sub>4</sub>	0	0.01	4.1	0.03
NMOG	0	0.01	0	0.03
Profile	1070	1071	1070	1071
<b>Reference</b>	Larson		DOE	

Table 5-30. Methanol processing from biomass

Process	IGT Fluidized Bed		Shell Entrained Bed	
Fertilizer NG <sup>a</sup> (Btu/gal)	1,350		1,090	
Feedstock harvesting and transport	5,930		4,800	
Diesel (Btu/gal)	0.05		0.04	
Electricity (kWh/gal)				
<b>Fuel Processing</b>				
Electricity				
Use (kWh/gal)	1.56		1.74	
Production (kWh/gal)	0.79		0.67	
Energy ratio (%)	52.4		64.7	
Feedstock (Btu/gal)	123,057		99,663	
Feedstock (lb/gal)	15.0		12.2	
Net combustion (Btu/gal)	16,690		2,667	
Emission Source	Vent	Process Gas Combustion	Vent	Process Gas Combustion
<b>Emissions (g/gal)</b>				
NO <sub>x</sub>	0	0.76	0	0.12
N <sub>2</sub> O	0	0	0	0
CO	0	0.26	0	0.04
CO <sub>2</sub> <sup>b</sup>	[5,451]	[817]	[5,613]	[77]
CH <sub>4</sub>	0	0.02	0	0.003
NMOG	0	0.02	0	0.003
Profile	1070	1071	1070	1071
<b>Reference</b>	Larson		Larson	

<sup>a</sup>NG = Natural gas.

<sup>b</sup>Values in brackets [ ] are actual emissions. However, fuel-cycle emissions are set to zero since this CO<sub>2</sub> represents carbon that was recently removed from the atmosphere.



**Figure 5-4. Methanol production from steam reforming of natural gas**

emissions per day was estimated for a 10,000-tons/day plant. Specific reactivity values were calculated for the NMOG compositions in the SPECIATE data base.

Energy consumption data for steam reforming and POX were obtained from several studies. Natural gas reformers are fueled with process gas left over from the methanol synthesis. This gas is primarily composed of hydrogen with CO, methane, CO<sub>2</sub>, and methanol. Emission factors for natural gas were used to estimate NO<sub>x</sub>, CO, methane, and NMOG emissions. CO<sub>2</sub> emissions are determined from a carbon balance. The difference between carbon in the natural gas feed and carbon in the natural gas product is carbon in the form of CO, hydrocarbon, or CO<sub>2</sub> emissions. Over 99 percent of this carbon is emitted as CO<sub>2</sub>. POX process produces NO<sub>x</sub> emissions since combustion with air does not occur. A small amount of pollutants are emitted from flaring purge gas. Several studies included energy consumption estimates for methanol production from natural gas, biomass, and coal (DeLuchi, 1991; Unnaşch, 1990; Dong, 1992; Katofsky, 1993; Larson, 1992; Sherwin, 1979; Supp, 1990).

Methanol plants can be either importers or exporters of electricity. Power generation emissions associated with net electric power were included with the fuel production emissions. Electricity demand for the POX process includes required energy for an oxygen plant.

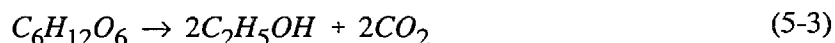
Synthesis gas from coal gasification can also provide a feedstock for methanol production. Numerous coal gasification systems have been studied and many of these considered for methanol production plants. Table 5-29 shows energy inputs and emissions based on several methanol production studies. Distillation vent emissions are taken to be the same as those from natural gas to methanol facilities. Similar to the POX process, no air combustion occurs and exhaust emissions are minimal. CO<sub>2</sub> is produced in a shift reactor or left over from methanol synthesis and emitted from a purge vent.

Coproducing methanol and electricity provides an opportunity to balance the load from coal gasification systems. With this process, synthesis gas from the gasifier passes over a methanol catalyst and the unreacted gas burned in a power plant. The Air Products LPMEOH process is particularly suited for once through type operations since a high methanol conversion can be achieved in a single pass through the catalyst. Biomass co-feedstocks such as sewage sludge have been considered as feeds for coal gasifiers but were not evaluated in this study.

### 5.2.3 Ethanol

A number of ethanol production feedstocks were considered. Ethanol from corn is the current fuel production technology. Experts in the ethanol production field indicate that the efficiency of ethanol plants has improved over the past decades. Newer plants consume about 14,000 Btu per gallon less energy than older plants. Process energy requirements for ethanol production are shown in Table 5-31.

Commercial ethanol is produced from the fermentation of sugars and starches with yeasts. Fermentation involves the biological decomposition of complex sugars into sucrose and their conversion to ethanol. Sucrose is converted into glucose through the following mechanism:



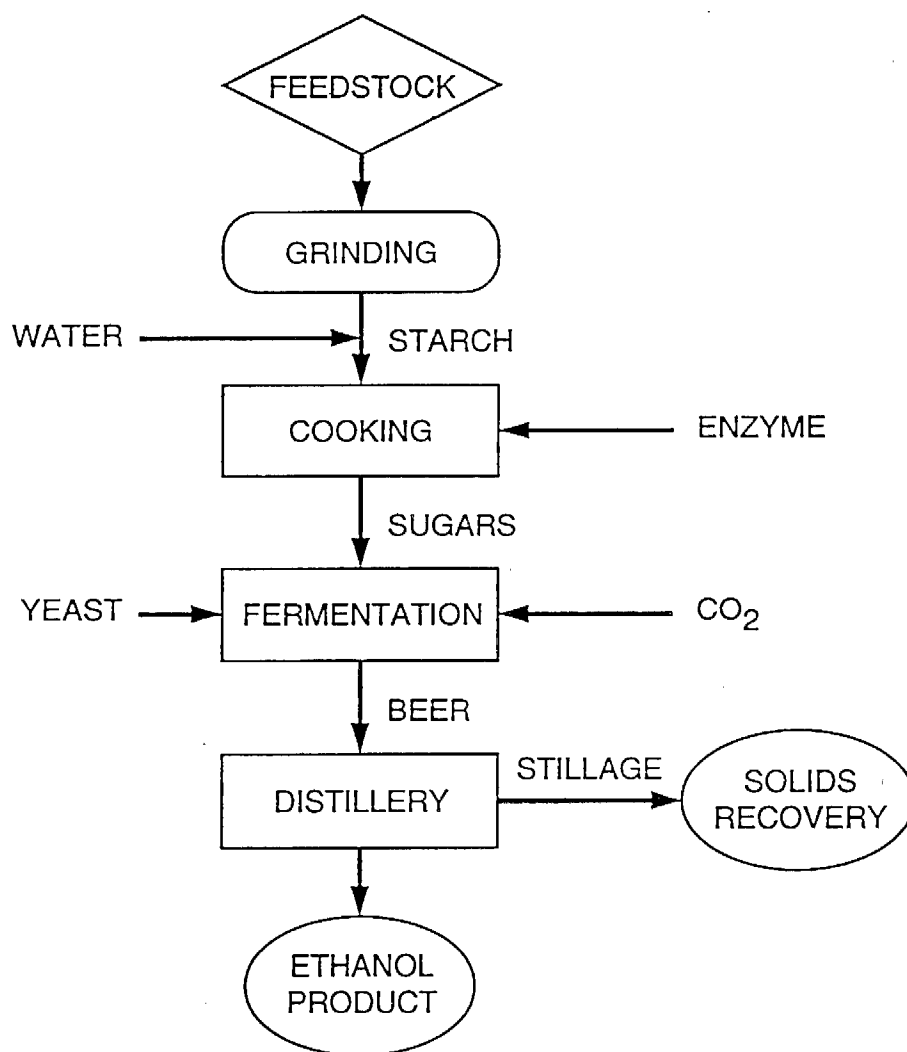
Currently annual production of ethanol in the U.S. is 1.4 billion gallons. Most of this ethanol is produced in the Midwest from corn feedstocks through the wet milling process. The steps for converting corn to ethanol are illustrated in Figure 5-5. Ethanol plants typically use a coal powered cogeneration system to produce electric power and steam for ethanol production. The wet milling plant produces 2.5 gallons of ethanol per bushel of corn in addition to 14.4 lb of gluten feed and meal and 1.6 lb of corn oil. The net energy requirements for ethanol plants have been increasing over the years. Modern efficient plants require about 34,000 Btu of steam energy per gallon of ethanol. 39 percent of the emissions from the ethanol plant were allocated to by-products (Unnasch, 1990). A similar allocation was assumed in two other ethanol processing studies (Ho, 1990). If corn processing plants operate continuously producing protein products and processing starch into either ethanol or corn sweetener.

**Table 5-31. Ethanol processing from corn, sugar cane, and biomass**

Process	Corn Fermentation		Sugar Cane Fermentation	Cellulosic Biomass Fermentation	
	High Efficiency	Low Efficiency		Low Efficiency	High Efficiency
<b>Feedstock Gathering</b>					
Fertilizer NG <sup>a</sup> (Btu/gal)	15,650	18,650	7,160	2,310	970
Growing, harvesting LPG (Btu/gal)	1,400	1,400	—	—	—
Diesel (Btu/gal)	10,080	10,080	21,180	10,150	6,240
Gasoline (Btu/gal)	2,840	2,840	—	—	—
Electricity (kWh/gal)			—	0.086	0.059
Feedstock transport Diesel (Btu/gal)	1,600	1,600	1,600		
<b>Fuel Processing</b>					
Electricity export use (kWh/gal)	1.5	1.5	0	1.85	1.7
Production (kWh/gal)	—	—	0	3.14	3.14
Energy ratio <sup>b</sup> (%)	43.7	40.8	15.0	39.9	58.7
Feedstock (Btu/gal)	159,000	159,000	386,000	211,400	143,700
Feedstock (dry lb/gal)	19.4	19.4	48	25.7	17.5
Net combustion (Btu/gal)	34,000	48,000	175,000	38,700	34,000
Fuel (lb/gal)	2.8	4.0	22	—	—
Byproduct credit (%)	39	39	4.5	0	0
<b>Emission Source</b>	<b>Coal Boiler</b>		<b>Bagasse Boiler</b>	<b>Biomass Boiler</b>	
<b>Reference</b>	Unnasch		Jenkins	Wyman	

<sup>a</sup>NG = Natural gas.

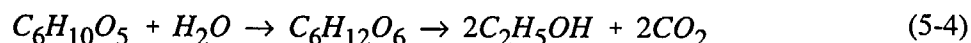
<sup>b</sup>Energy ratio represents energy of fuel product/total energy inputs = ethanol HHV (84,400 Btu)/(feedstock + fuel)Btu. The energy ratio does not take into account exported electricity. The energy ratio is often used to characterize fuel production processes.



**Figure 5-5. Ethanol production from corn**

About 7 million gallons of ethanol are currently produced in California from materials including cheese whey, waste fruit, and waste candy. One facility is located in Riverside, California, and is the basis for Scenario 1. Processing waste material requires less energy than corn processing and no energy is associated with gathering or transporting the feedstock for the specific case where the waste material would need to be hauled away for disposal. The facility in Riverside uses a boiler to generate steam for distillation and processing. Scenario 2 is based on ethanol production from corn in the Midwest. Table 5-31 shows the energy inputs for ethanol production. Emissions include combustion emissions for steam generation, distillation vents, and fugitive emissions. Combustion emissions are accounted for in Btu/gal. Feedstock transportation requirements are based on the amount of feedstock required per gallon of ethanol.

Most of the corn kernel is starch, which can be readily fermented into ethanol. However, other biomass materials, such as energy crops, wood waste, and agricultural waste, contain a cellulose and hemicellulose which can be converted to sugars for fermentation into ethanol. Cellulose must be reacted with water (hydrolysis) before it can be converted to ethanol through the following mechanism:



A substantial research effort is underway to commercialize processes for the conversion of cellulose products to ethanol. The steps for converting hemicellulose and cellulose into sugars and fermentation are shown in Figures 5-6 and 5-7. The lignin fraction of biomass cannot be converted to ethanol but can be used to generate steam. Cellulose conversion or hydrolysis can be performed in separate steps or in a combined reaction (Simultaneous Saccharification and Fermentation [SSF]). Scenarios 3 and 4 are based on the conversion of biomass to ethanol. Energy crops are assumed for Scenario 3 and waste biomass for Scenario 4. Combustion emissions are based on the Btu per gallon of ethanol.

#### 5.2.4 Natural Gas

The production and distribution of natural gas consists of transporting the fuel in high pressure pipelines to gas clean up facilities. Emissions are broken up into compression energy for pipeline transport and fugitive emissions. Emissions from CNG compression and fueling facilities are covered in Section 5.3. Transportation distances in Section 5.1 correspond to the compression energy for transporting natural gas and providing sufficient pressure drop for processing facilities.

Fugitive emissions from gas production were estimated by GRI. Emissions from gas compressors are discussed in Section 5.1. The gas clean up and extraction process for CNG and LNG are the same. Some LNG may be imported.

Table 5-32 shows an accounting of natural gas fugitive losses based on a study by the Gas Research Institute. The grouping of emission sources in the table was used to determine the split among fuel-cycle phases. The emissions rate for fugitive losses was determined from the annual emissions divided by annual production. Based on this data, fugitive losses in the U.S. represent 0.8 percent of total throughput.

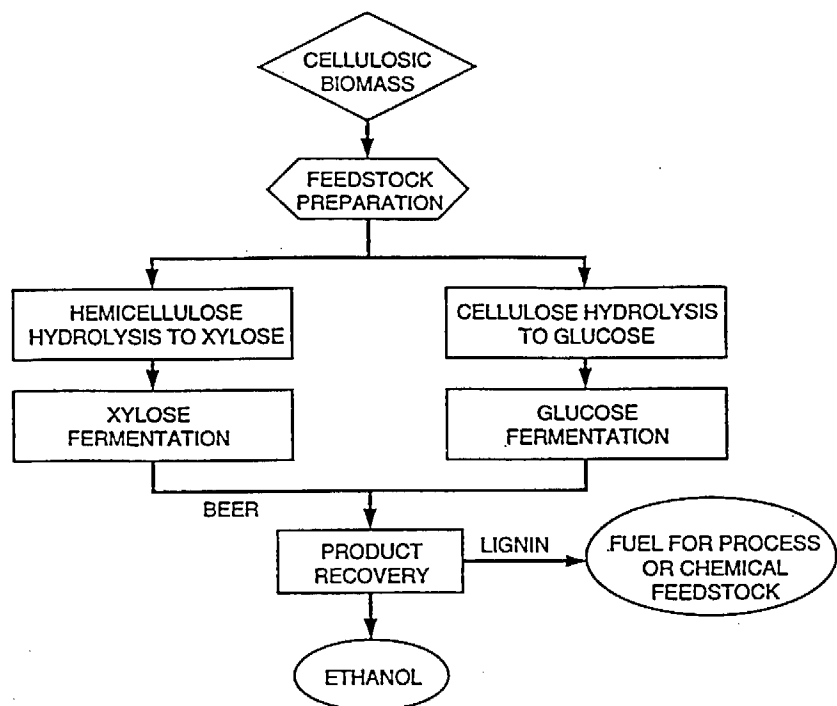


Figure 5-6. Ethanol from cellulosic biomass

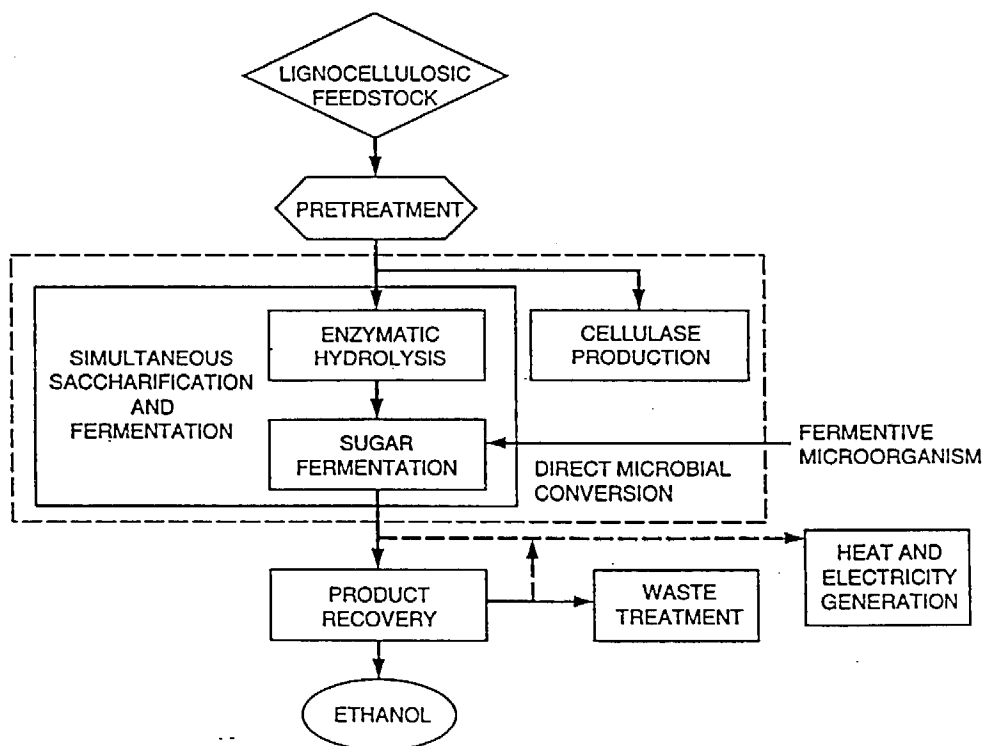


Figure 5-7. Simultaneous saccharification and fermentation

**Table 5-32. Fugitive emissions from natural gas operations**

<b>Category</b>	<b>Emissions<sup>a</sup> (U.S. Bcf/y)</b>	<b>VOC<sup>b</sup> Emissions (g/100 scf)</b>	<b>Source Code</b>
Wells	1.0	0.29	n11.2
Gathering lines	1.8		
<b>Production</b>	<b>2.8</b>		
Separators	1.4		
Heaters	0.5		
Dehydrators	0.2		
Meters	0.4		
Gas plants	0.7		
Maintenance	23		
Mishaps	3	3.05	n31.1
<b>Processing</b>	<b>29.2</b>		
Compressor stations	13.0	8.67	n53.1
M&R stations	16.0		
Pneumatics, starts/stops, vents	54		
<b>Transmission</b>	<b>83.0</b>		
<b>Storage</b>	—	0.4 <sup>c</sup>	n61.1
Mains	16.5	5.04	n73.1
Services	3.0		
Regulators	16.8		
M&R	5.0		
Customer meters	7.0		
<b>Distribution</b>	<b>48.3</b>		
<b>Total</b>	<b>163.3</b>	<b>17.45</b>	—

<sup>a</sup>GRI estimates (Lott, 1992).

<sup>b</sup>Based on U.S. production of 20,000 Bcf/y (A.G.A., 1992).  
91% of VOC is CH<sub>4</sub>, balance is NMOG (Table 2-8).

<sup>c</sup>Leaks based on Thomason, 1993.

Gas sweetening plants produce fugitive losses of heavy glycols. These emissions translate to less than 0.2 g/100 scf. Methanol is used in drying systems for local compressors. The volume of methanol is negligible.

Emissions from natural gas distribution include local distribution/compression and storage emissions in the South Coast Air Basin as well as emission associated with final compression to produce CNG. Local distribution requires relatively little compression energy since the gas is already transmitted to California at 800 psi. Some gas is stored underground in Southern California. These emissions were not included in the GRI study and were estimated from comments received on this study (Thomason, 1993). Table 5-33 shows the natural-gas-to-CNG and natural-gas-to-LNG processing energy values for Scenarios 1 through 4.

The same natural gas production emissions were assumed for LNG production. Transportation distances are outlined in Section 5.1. Fugitive emissions associated with LNG production include those for production, processing, pipeline transmission, and transport. These include fugitive losses from natural gas production as well as evaporative losses from LNG bulk storage. Storage losses from bulk storage and tanker ships are 0.1 percent per day (Timmerhaus). Storage losses are assumed to be recovered and recompressed at the liquefaction facility. The lost product is considered in the total natural gas required per gallon of LNG. LNG liquefaction requires from 15 to 20 percent of the energy input to power compressors. This energy can be provided with natural gas powered reciprocating engines or gas turbines as well as electric motors. Liquefaction energy is counted under production Phase 3. Scenario 1 is based on a pressure let down facility in Wyoming. A modest energy input is assumed from natural gas powered reciprocating engines. Scenarios 2, 3 and 4 assume liquefiers in the California, outside the South Coast Air Basin. The energy input decreases throughout these scenarios as with varying degrees of integration with pressure let down requirements of the pipeline gas. Fuel-cycle emissions for natural gas production were included as part of the fuel-cycle emissions for all other fuels in proportion to natural gas consumption.

### 5.2.5 Hydrogen

Many different methods of hydrogen production are possible. The primary methods in use today derive hydrogen from fossil fuels; these methods are methane reforming, oxidation of oils, and coal gasification. 100 to 200 plants currently produce hydrogen in the United States (CEC ). In the late 1970s, over 2 trillion ft<sup>3</sup> of hydrogen were produced per year (Shreve).

**Table 5-33. Natural gas processing energy**

Process	Natural Gas to CNG	Natural Gas to LNG <sup>a</sup>
Gas processing energy	300 Btu/100 scf	250 Btu/gal
Compression/liquefaction power/energy	Scenarios 1, 2 1.2 kWh/100 scf Scenarios 3, 4 1.0 kWh/100 scf	0.4 kWh/gal and 0 Btu/gal (1) 20,600 Btu/gal (2) 18,300 Btu/gal (3) 18,300 Btu/gal (4)

<sup>a</sup>Natural gas energy inputs (assumed for reciprocating engine) for Scenarios shown in ( ).

Non-fossil-fuel methods of hydrogen production include electrolysis of water, thermochemical splitting of water, and photolysis. The following sections describe these methods.

Electrolysis separates fresh or desalinated water into hydrogen and oxygen by passing current through an electrochemical cell suspended in a water-based electrolyte. Conventional electrolysis technology, using an electrolyte in a liquid solution, is well developed. Electrical to hydrogen energy conversion efficiencies as high as 82 percent are being achieved, and current research aims to increase this further. The gaseous hydrogen obtained from electrolysis is over 99.9 percent pure, compared to 98 percent purity for fossil-fuel hydrogen (Bockris). In current practice, byproduct oxygen is often discarded unless useable onsite (Shreve).

Electricity is the primary energy input to the electrolysis process. (In fact, it is the only energy input for all methods of hydrogen production except high temperature steam electrolysis and photoelectrolysis.) This electricity can be acquired from a variety of sources. These sources include photovoltaic, solar thermal, nuclear (fusion or fission), hydro, geothermal, wind, ocean swell and wave energy conversion (OSWEC), ocean thermal energy conversion (OTEC), and others. Nuclear, geothermal, and solar thermal energy sources produce heat in addition to producing electricity and can therefore provide energy input.

Process energy requirements for hydrogen production are shown in Table 5-34. Several feedstocks can be used to make process gas for hydrogen production. Natural gas is the most predominant near-term feedstock. Emissions from producing hydrogen from electrolysis were considered to be zero.

A formidable amount of power is required to liquefy hydrogen. Hydrogen is compressed, cooled with refrigeration, expanded, and cooled again. The power required for liquefaction ranges from 25 to 39 percent of the hydrogen fuel energy (DeLuchi, 1989). Magnetic liquefaction systems can liquefy hydrogen with 25 percent power input while conventional compressions systems require more energy. For example, 100,000 Btu of hydrogen (29.3 kWh of thermal energy) would require at least 7.3 kWh of mechanical power for liquefaction. This power requirement is notable when expressed in terms of thermal energy input. Approximately 70,000 Btu of natural gas would be required to produce 7.3 kWh of mechanical power to liquefy 100,000 Btu of hydrogen (assuming a 25-percent power input).

Combining a liquefaction system with a biomass gasification system would allow for some advantages in heat recovery and cooling that may reduce the overall energy input for liquefaction. Liquefaction is complicated by the fact that liquid hydrogen vaporizes in a perfectly insulated container because of its molecular properties. At ambient temperature, 75 percent of the atoms are in the ortho quantum state, but at liquid conditions 99 percent of the atoms must be in the para quantum state. As the ortho atoms convert, they generate heat and vaporize liquid. In order to prevent the loss of liquid, hydrogen is passed over a catalyst prior to liquefaction. Table 5-35 shows the processing energy and liquefaction power assumptions for solar, natural gas, and biomass derived hydrogen. Electric liquefaction is assumed for solar derived compressed hydrogen while a reciprocating natural gas engine provides power for the natural gas and biomass cases (Scenarios 2, 3, and 4).

Table 5-34. Hydrogen processing from biomass, coal, and natural gas

Process	IGT Biomass Gasification	Shell Coal Gasification	Natural Gas Reforming
Fertilizer NG <sup>a</sup> (Btu/lb H <sub>2</sub> )	1,080	0	0
Feedstock extraction			
Diesel (Btu/lb H <sub>2</sub> )	4,740	1,160	7,040 Btu NG
Electricity (kWh/lb H <sub>2</sub> )	0.04	—	—
Feedstock transport	—	3,930	5,000 Btu NG
diesel (Btu/lb H <sub>2</sub> )			
<b>Fuel Processing</b>			
Electricity			
Use (kWh/lb H <sub>2</sub> )	2.08	2.16	0
Production (kWh/lb H <sub>2</sub> )	0.0	0.25	0
Energy ratio (%)	62.0	77.7	61.1
Feedstock			
(Btu/lb H <sub>2</sub> )	98,550	78,636	100,000
(feedstock/lb H <sub>2</sub> )	12.0 lb	9.6 lb	9700 scf
Net combustion (Btu/lb H <sub>2</sub> )	13,500	2,536	52,830
<b>Reference</b>	Larson	Larson	Shreve

<sup>a</sup>NG = Natural gas required for ammonia production. Fuel-cycle emissions are associated with an ammonia plant.

Table 5-35. Energy inputs for hydrogen production, liquefaction, and compression (energy/lb hydrogen)

Process	Solar Hydrogen	Natural Gas Reforming	Biomass Gasification
Feedstock input	Solar	100,000 Btu NG <sup>a</sup> 0.97 100 scf 52,830 Btu combustion	Btu biomass <sup>a</sup> 9.6 lb biomass 2540 Btu combustion
Compression/liquefaction energy % of hydrogen per lb hydrogen	7.2% <sup>b</sup> 1.3 kWh/lb electricity	35% <sup>b</sup> 50,100 Btu NG 0.48 100 scf NG	30% <sup>b</sup> 42,900 Btu NG 0.42 100 scf NG

<sup>a</sup>Feedstock input is adjusted upward by 1 percent to account for liquid hydrogen losses in the VIEW data base.

<sup>b</sup>Power expressed as a percentage of hydrogen's HHV: 61,100 Btu/lb hydrogen.

### 5.2.6 Electricity

Emissions associated with electricity production depend upon the feedstock and type of power generation, and the mix of resources used to supply the electricity. The following electric generation mixes were considered:

- Incremental generation for EV charging with several possible scenarios
- Average South Coast Air Basin mix generation
- Average California, non-South Coast Air Basin generation
- U.S. average generation

The above power generation mixes reflect those resources that are used to supply the South Coast Air Basin with electricity, i.e., the amount of power that comes from sources within the South Coast Air Basin, from California, non-South Coast Air Basin sources, and from out-of-state sources.

Power plant emissions depend upon the mix of power generation equipment, feedstocks, and the type of emission control systems used to generate electricity. Depending on the equipment (i.e., turbine, boiler, internal combustion engine), the fuel (i.e., natural gas, landfill gas, municipal refuse), and whether or not the facility is utility owned or private, different emission regulations apply. A computer model called ELFIN (ELectricity FINance) was developed by the Environmental Defense Fund (EDF) to evaluate utility operations. The model considers electrical load and the dispatching of power plants. This model has been used by the CEC and others to determine the incremental power generation emissions for electric vehicles. The CEC performed a series of ELFIN runs (Tanghetti, 1995) for the two major utilities in the South Coast Air Basin — Southern California Edison (SCE) and the Los Angeles Department of Water and Power (LADWP) — to evaluate incremental power generation emissions for the following EV implementation scenarios:

- Various levels of EV penetration for different utilities with the following off-peak/on-peak charging profiles and EV energy consumption (efficiency):
- 80% off-peak/20% on-peak charging, 0.24 kWh/mile EV efficiency
- 80% off-peak/20% on-peak, 0.35 kWh/mile
- 95% off-peak/5% on-peak, 0.24 kWh/mile
- 95% off-peak/5% on-peak, 0.35 kWh/mile

These modeling studies usually consider assumptions on the number of EVs, their annual mileage, and average energy consumption. These parameters are used to determine the amount of power generated. Generation emissions are then estimated for different years and implementation scenarios. Generation emissions change with different years due to variations in total power demand, the EV population and miles traveled, and emission control systems that are in place on power plants. The incremental emissions associated with EV charging depends on the total power demand for EVs, as a function of day/night charging profile and energy consumption. The ELFIN model assumes the South Coast Air Basin charging profiles to have the shape shown in Figure 5-8, whereas SCE predicts that EV charging will effect their overall demand profile as shown in Figure 5-9. Based on the time of day for charging, this profile appears to be about 95 percent off-peak. The effect of more off-peak charging is that more power can be produced in the South Coast Air Basin, when the system is operating far below capacity. With heavier on-peak charging, the extra load on the system requires that more power be imported from sources outside the South Coast Air Basin, primarily from the Pacific Northwest. The power plant mix does not react to the number of EVs or their individual

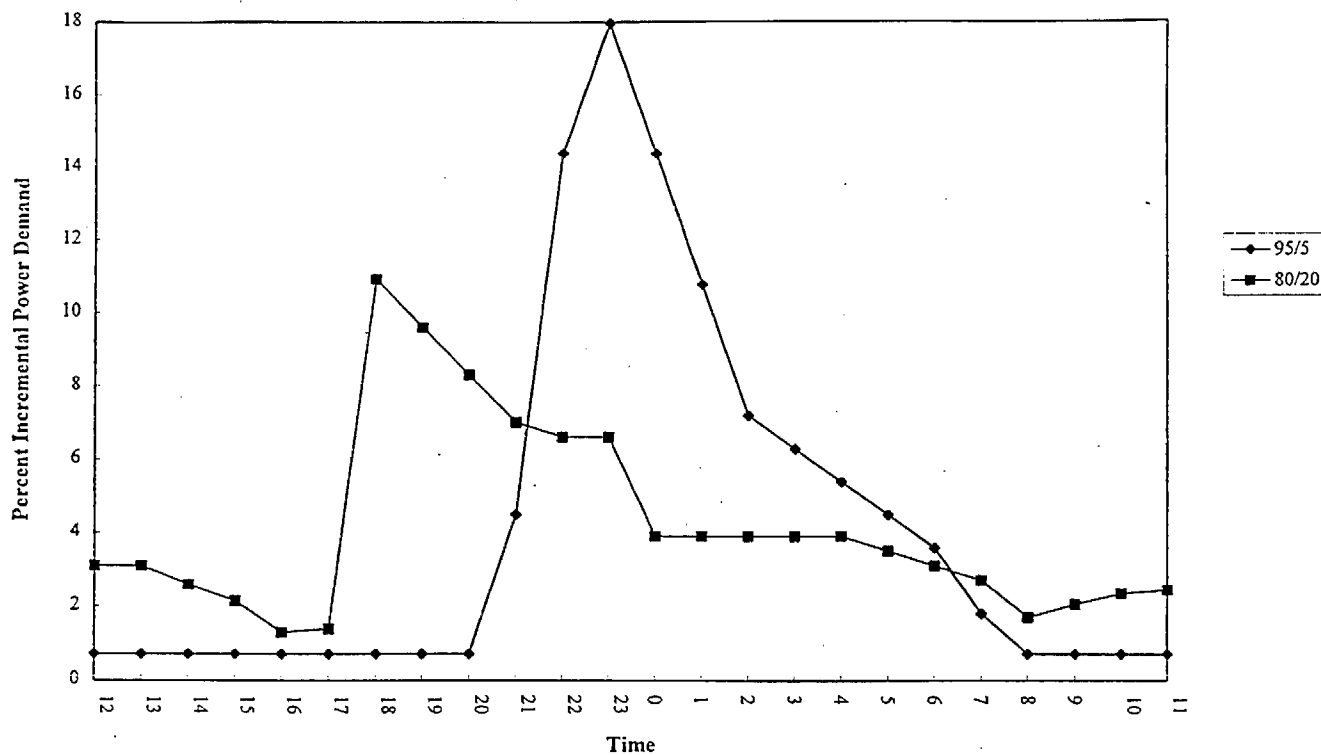


Figure 5-8. Charging profile for South Coast Air Basin

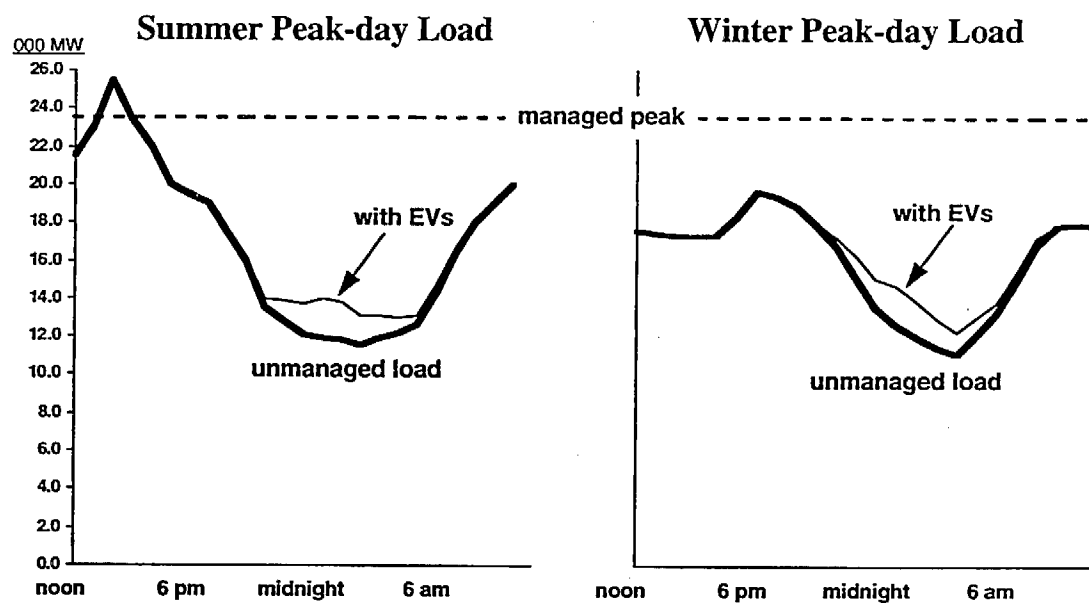


Figure 5-9. Southern California Edison load shape, 2010

energy consumption, but, rather, to their total energy consumption. Therefore, evaluating the effect of total power demand on the power generation emission rate is very illustrative. The emission rates from different charging scenarios will be applied to the scenarios in this study. The following pages first present impact of the confusing array of charging options on power generation emissions on a g/kWh basis.

Figures 5-10, 5-11 and 5-12 show the average and EV-related  $\text{NO}_x$  emissions from power generation, on a grams per kilowatt-hour basis, based on the ELFIN runs for SCE and the LADWP. These ELFIN runs were based on the EV power demand assumptions for the years 2000, 2005, and 2010, 40% EV distribution. According to the model,  $\text{NO}_x$  emissions for the Basin do tend to drop in the future, but vary only slightly within the range of energy demand (i.e., 0.24 kWh/mile vs. 0.35 kWh/mile). Therefore, it is quite accurate within the context of daytime/nighttime charging assumptions to use the emissions rate for any set of EV energy demand that lies within the line segments in these charts. While only the 40% distribution scenario is presented here on a gram per kilowatt-hour basis, the same trend is true for the 55% and 80% distribution scenarios as well.

The ELFIN model predicts that there will be incremental emissions in the South Coast Air Basin from electric power generation for EVs. While there will be incremental power generation, there cannot be incremental emissions under the strict emission rules of the South Coast Air Quality Management District (SCAQMD). Currently, all utility-owned power generation facilities are subject to SCAQMD Rule 1135, and qualifying facilities (QFs), which are not utility owned, but utilities are required to purchase power from them, are subject to other SCAQMD Regulation 11 rules (1109,

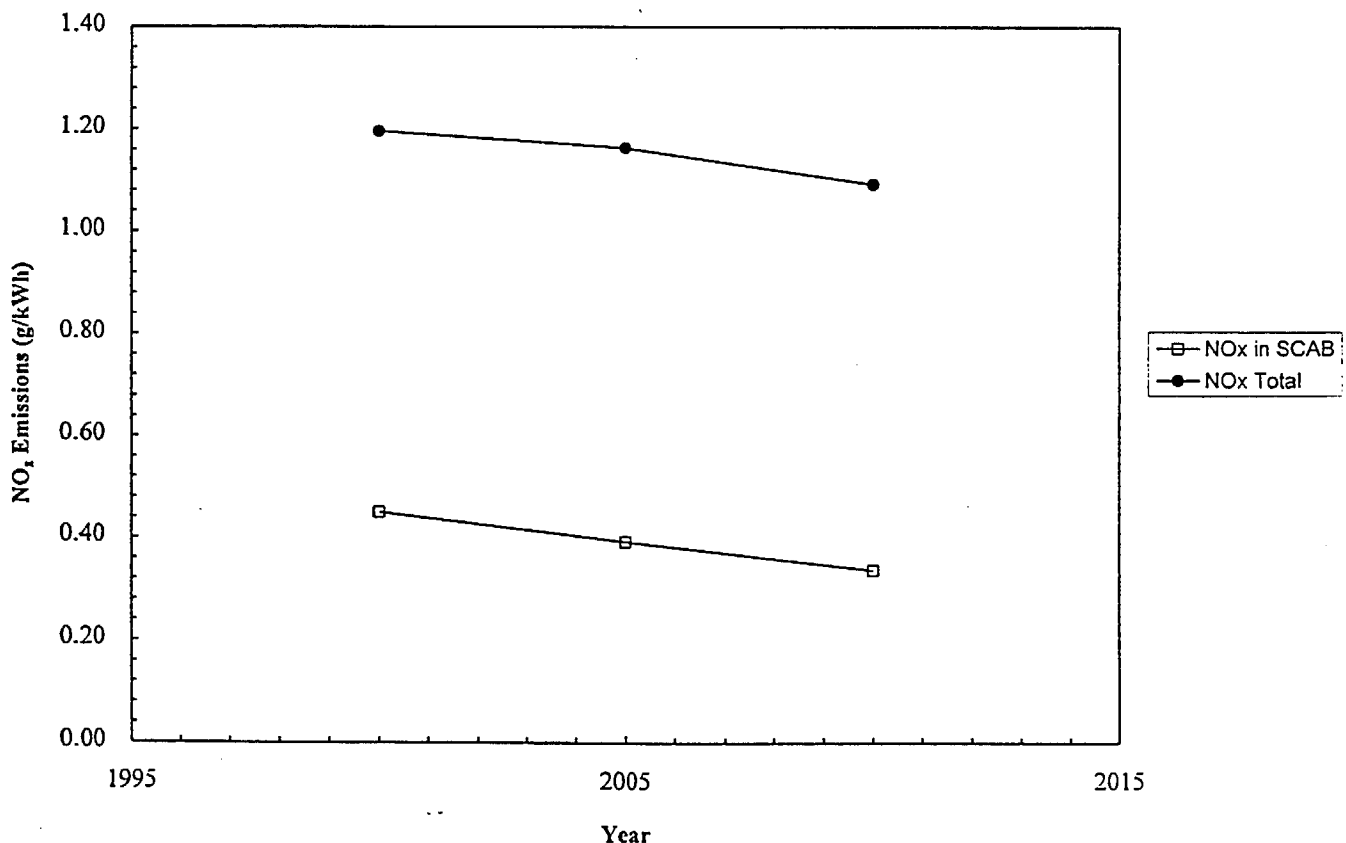


Figure 5-10. Average  $\text{NO}_x$  emissions in the South Coast Air Basin, no EVs

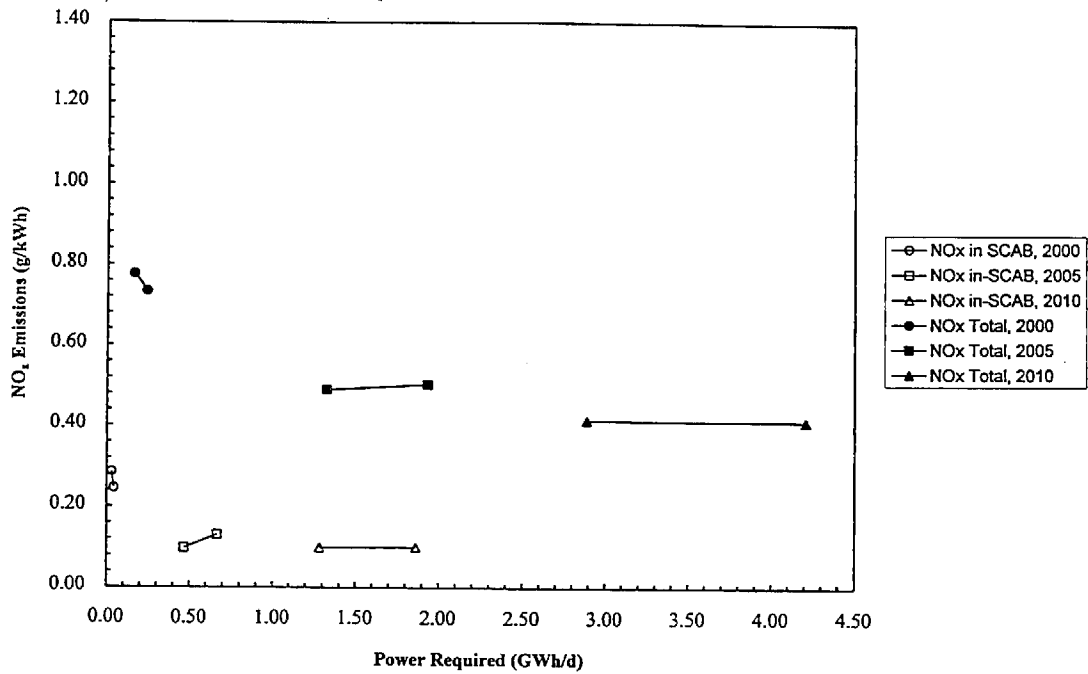


Figure 5-11. NO<sub>x</sub> emissions from EV use in the South Coast Air Basin, 80/20 charging

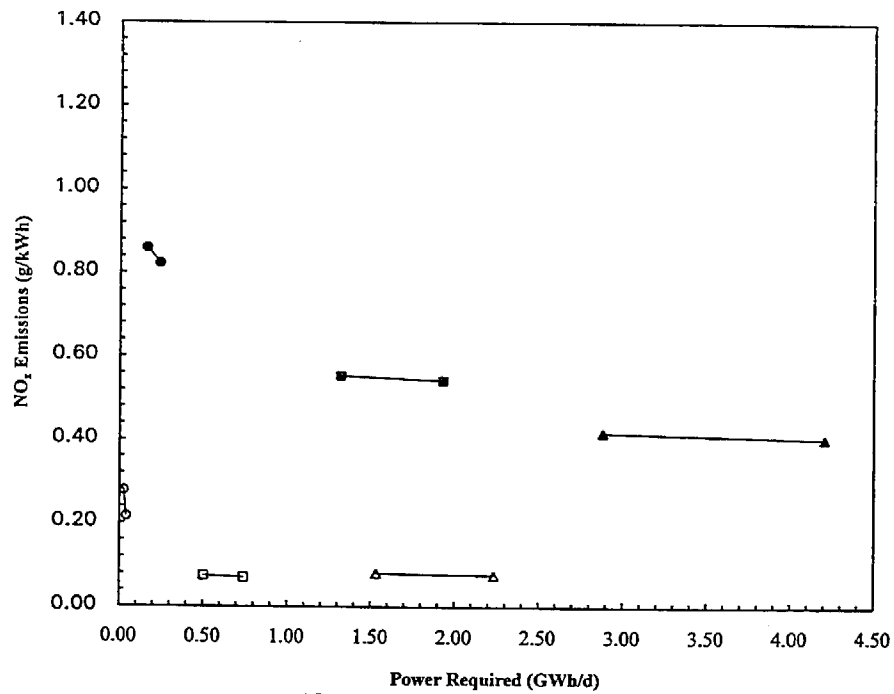


Figure 5-12. NO<sub>x</sub> emissions from EV use in the South Coast Air Basin, 95/5 charging

1110.2, 1134, and 1146) or BACT rules to reduce emissions. Regulation 11 limits were summarized in Table 5-1. The Regulation 11 rules limit the facilities to very low emission levels, while the BACT rules either place an emissions cap on the facility or prescribe a specific control technology. At the beginning of 1994, SCAQMD began a new program called RECLAIM (Regional Clean Air Incentives Market), which places even stricter emission caps on facilities, but allows them to buy and sell emission credits, if they are under or over their limit, instituting a bubble policy over the South Coast region.

Most facilities are currently being phased into RECLAIM, but are still subject to Regulation 11 or BACT, until they come into compliance with RECLAIM. Under RECLAIM, there are exemptions for municipal refuse fired facilities that are publicly-owned, landfill gas-fired and energy recovery facilities, and the cities of Burbank, Glendale, and Pasadena. The rest of the South Coast region will be subject to RECLAIM. Those facilities that are exempt from RECLAIM will still be subject to Regulation 11 rules or BACT.

ELFIN projects emission rate for qualifying facilities (QFs) that are an order of magnitude higher than for utility-owned facilities in the South Coast Air Basin in all scenarios. For example, for the SCE region, the average emission factor for  $\text{NO}_x$  is 0.13 g/kWh (0.28 lb/MWh) for utility owned facilities, but the factor for QFs is 1.97 g/kWh (4.35 lb/MWh). The QF mix in the South Coast Air Basin emit at higher rates than utility power plants. Such high emission rates might be expected from facilities that are only subject to Rule 474 (See Table 5-1), however such facilities are old, given that this is a relatively old rule compared to the Regulation 11 rules and the BACT rules. Thus, the percentage of these older facilities in the Basin is probably less than that predicted by ELFIN. The ELFIN input data indicate a small percentage of high-emitting QFs; however, they would not be allowed to operate at the high emission rates predicted for some of these facilities in ELFIN, such as 8.13 g/kWh (17.9 lb/MWh). Given the mix of QFs in ELFIN, and the SCAQMD rules that apply to them, a more reasonable estimate of the average  $\text{NO}_x$  emission factor for QFs in the South Coast Air Basin is approximately 1 g/kWh (2 lb/MWh).

The RECLAIM  $\text{NO}_x$  limits for SCE and LADWP for the years 2000 and 2010 are:

	<u>2000</u>	<u>2010</u>
Edison	1631 tons/yr	1219 tons/yr
LADWP	578 tons/yr	418 tons/yr

ELFIN predicts that Edison will exceed their RECLAIM  $\text{NO}_x$  limit for a few of the scenarios in the year 2010, and that LADWP will exceed RECLAIM for every scenario. The ELFIN projections can be seen in Figures 5-13 and 5-14. Since the utilities and QFs will be required to meet RECLAIM, either by reducing the actual emissions to the specified level, or by purchasing credits from facilities that are below the limit, there can be no incremental emissions in the South Coast Air Basin from EV charging. In fact, RECLAIM limits will be lower than current Regulation 11 limits, resulting in a reduction of total emissions in the South Coast Air Basin. EVs could only create incremental emissions in the South Coast Air Basin if the utilities were below their permitted levels before the introduction of EVs, and, rather than sell their RECLAIM credits, they retired them. Thus the introduction of EVs would then cause their emission levels to increase, but must still be kept at or below the RECLAIM level. An example of this scenario is shown in Figure 5-15.

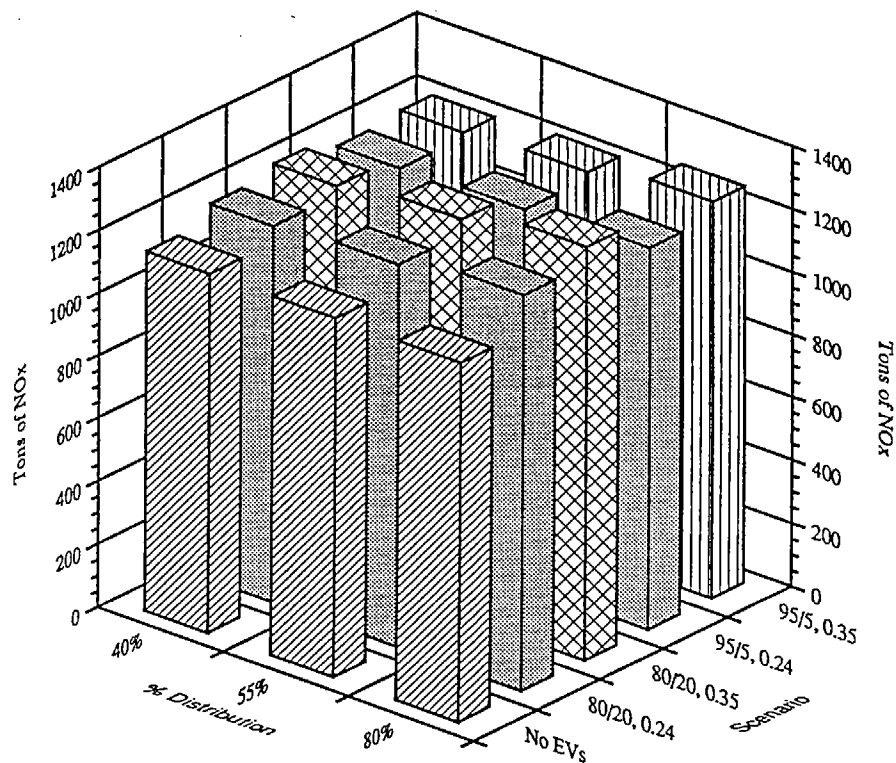


Figure 5-13. Total tons of SCE NO<sub>x</sub> in the South Coast Air Basin, 2010

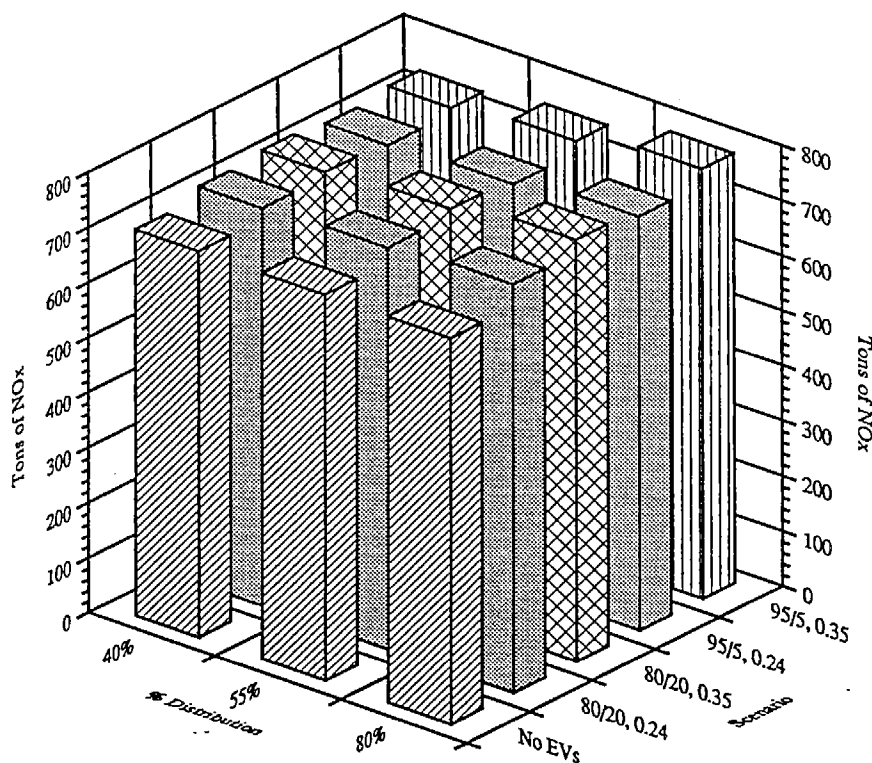
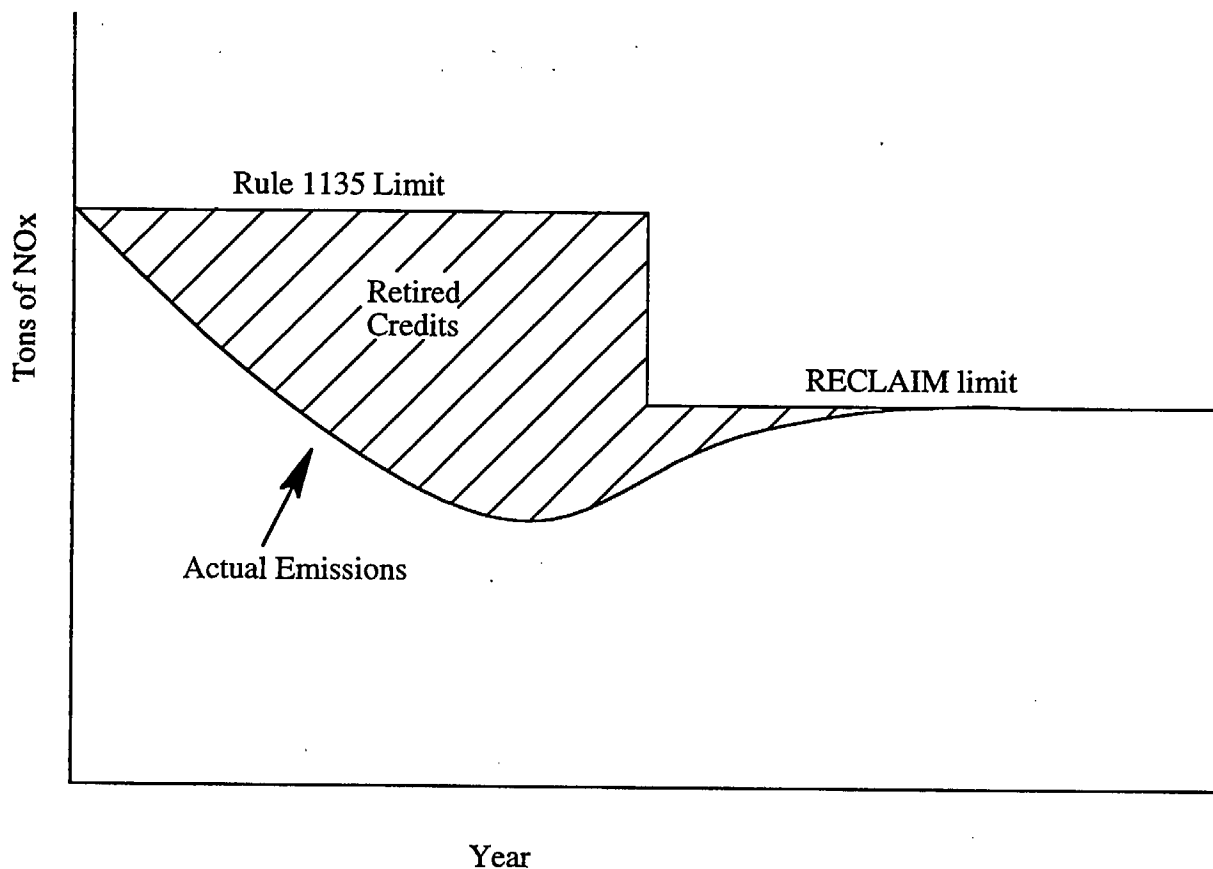


Figure 5-14. Total tons of LADWP NO<sub>x</sub> in the South Coast Air Basin, 2010



**Figure 5-15. Possible scenario for incremental EV emissions**

Tables 5-36, 5-37, and 5-38 summarize the emissions from CEC's ELFIN analysis. Table 5-36 shows the emissions without EVs which represents the total emissions in the South Coast Air Basin and the total electric power consumption. Tables 5-37 and 5-38 show the emissions and power generation associated with EV use. The CEC analysis considers a wide range of EV usages and EV energy consumption rates; however, these assumptions have little effect on the g/kWh emission rate. The mix of charging profiles has a more substantial effect on emissions in the South Coast Air Basin and is shown in Tables 5-37 and 5-38. These tables show the incremental emissions and power generation associated with EV charging. For Scenarios 2, 3, and 4, this study uses the values in Tables 5-37 and 5-38 as a basis for the average emissions associated with EV usage which treats EVs as a new alternative fuel with additional production capacity existing power generation. Marginal emissions associated with EV operation reflect RECLAIM considerations for NO<sub>x</sub> and do not include pipeline fugitive emissions for natural gas distribution.

This study uses the results of the ELFIN emission projections as the basis for determining average EV charging emissions according to the following scenarios:

- Scenario 1: Year 2000 emissions (Table 5-36)
- Scenarios 2, 3: Year 2010 emissions, charging 80/20 profile (Table 5-37)
- Scenario 4: Year 2010 emissions, charging 95/5 profile (Table 5-38)

Table 5-36. South Coast Air Basin average utility emissions

Base Case: No EVs												
	2000				2005				2010			
	GWh	% Energy	Tons	g/kWh	GWh	Tons	g/kWh	% Energy	GWh	Tons	g/kWh	g/ΣkWh
Total SCAB												
NO <sub>x</sub>	23,660	17.60%	12,167	0.467	28,559	12,356	0.393	21.68%	33,834	12,571	0.337	0.073
NMOG	23,660	17.60%	2,267	0.087	28,559	2,286	0.073	21.68%	33,834	2,303	0.062	0.013
CH <sub>4</sub>	23,660	17.60%	2,041	0.078	28,559	2,057	0.065	21.68%	33,834	2,072	0.056	0.012
CO	23,660	17.60%	4,050	0.155	28,559	6,098	0.194	21.68%	33,834	4,250	0.114	0.025
CO <sub>2</sub>	23,660	17.60%	15,704,517	602.693	28,559	18,208,087	578.897	21.68%	33,834	20,914,289	561.272	121.659
In-State, Non-SCAB												
NO <sub>x</sub>	33,880	25.21%	8,710	0.233	34,556	11,252	0.296	22.46%	35,052	10,927	0.283	0.064
NMOG	33,880	25.21%	2,071	0.055	34,556	1,971	0.052	22.46%	35,052	1,858	0.048	0.011
CH <sub>4</sub>	33,880	25.21%	1,864	0.050	34,556	1,774	0.047	22.46%	35,052	1,672	0.043	0.010
CO	33,880	25.21%	4,665	0.125	34,556	4,352	0.114	22.46%	35,052	4,053	0.105	0.024
CO <sub>2</sub>	33,880	25.21%	9,259,239	248.153	34,556	8,717,027	229.049	22.46%	35,052	9,588,069	248.375	55.774
Out-of-State, U.S.												
NO <sub>x</sub>	55,821	41.53%	77,358	1.258	58,139	77,352	1.208	37.85%	59,077	77,185	1.186	0.449
NMOG	55,821	41.53%	807	0.013	58,139	862	0.013	37.85%	59,077	915	0.014	0.005
CH <sub>4</sub>	55,821	41.53%	726	0.012	58,139	776	0.012	37.85%	59,077	823	0.013	0.005
CO	55,821	41.53%	4,480	0.073	58,139	4,538	0.071	37.85%	59,077	4,569	0.070	0.027
CO <sub>2</sub>	55,821	41.53%	37,439,439	609.005	58,139	38,227,981	597.038	37.85%	59,077	38,854,534	597.182	226.019
Other												
NO <sub>x</sub>	21,037	15.65%	79,545	3.433	24,811	86,533	3.167	18.02%	28,130	87,392	2.821	0.508
NMOG	21,037	15.65%	25,691	1.109	24,811	26,516	0.970	18.02%	28,130	26,694	0.862	0.155
CH <sub>4</sub>	21,037	15.65%	23,122	0.998	24,811	23,864	0.873	18.02%	28,130	24,025	0.775	0.140
CO	21,037	15.65%	13,937	0.602	24,811	14,256	0.522	18.02%	28,130	14,328	0.462	0.083
CO <sub>2</sub>	21,037	15.65%	8,454,200	364.903	24,811	8,636,591	316.071	18.02%	28,130	8,677,533	280.102	50.4776
Total												
NO <sub>x</sub>	134,397	100.00%	177,780	1.201	146,065	187,493	1.166	100.00%	156,093	188,076	1.094	1.094
NMOG	134,397	100.00%	30,836	0.208	146,065	31,636	0.197	100.00%	156,093	31,769	0.185	0.185
CH <sub>4</sub>	134,397	100.00%	27,753	0.187	146,065	28,472	0.177	100.00%	156,093	28,592	0.166	0.166
CO	134,397	100.00%	27,132	0.183	146,065	29,243	0.182	100.00%	156,093	27,199	0.158	0.158
CO <sub>2</sub>	134,397	100.00%	70,857,395	478.719	146,065	73,789,687	458.706	100.00%	156,093	78,034,425	453.930	453.930

Table 5-37. South Coast Air Basin utility emissions related to EV charging — 80/20 charging

40% Distribution, 80/20 Charging, 0.35 kWh/mi														
	2000					2005					2010			
	GHWh	% Energy	Tons	g/kWh	GHWh	Tons	g/kWh	% Energy	Tons	GHWh	% Energy	Tons	g/kWh	g/\$kWh
Total SCAB														
NO <sub>x</sub>	31.7	26.05%	8,547	0.245	418	60,103	0.131	1,053	48.97%	114,200	0.099		0.048	
NMOG	31.7	26.05%	0.606	0.017	418	9,413	0.020	1,053	48.97%	18,694	0.016		0.008	
CH <sub>4</sub>	31.7	26.05%	0.546	0.016	418	8,472	0.018	1,053	48.97%	16,824	0.015		0.007	
CO	31.7	26.05%	4,495	0.129	418	45,765	0.099	1,053	48.97%	100,734	0.087		0.043	
CO <sub>2</sub>	31.7	26.05%	21,168	605.648	418	272,001	590.822	1,053	48.97%	610,735	526.776		257.955	
In-State, Non-SCAB														
NO <sub>x</sub>	32.7	26.83%	10,920	0.303	216	57,522	0.242	467	21.74%	125,922	0.245		0.053	
NMOG	32.7	26.83%	2,367	0.066	216	15,923	0.067	467	21.74%	27,459	0.053		0.012	
CH <sub>4</sub>	32.7	26.83%	2,130	0.059	216	14,331	0.060	467	21.74%	24,713	0.048		0.010	
CO	32.7	26.83%	8,683	0.241	216	57,122	0.240	467	21.74%	106,752	0.207		0.045	
CO <sub>2</sub>	32.7	26.83%	17,325	481.165	216	116,021	487.757	467	21.74%	248,094	481.916		104.787	
Out-of-State, U.S.														
NO <sub>x</sub>	57.2	46.94%	77,050	1.223	352	426,240	1.100	629	29.27%	732,010	1.056		0.309	
NMOG	57.2	46.94%	0.722	0.011	352	4,169	0.011	629	29.27%	7,368	0.011		0.003	
CH <sub>4</sub>	57.2	46.94%	0.650	0.010	352	3,752	0.010	629	29.27%	6,632	0.010		0.003	
CO	57.2	46.94%	1,776	0.028	352	9,695	0.025	629	29.27%	14,684	0.021		0.006	
CO <sub>2</sub>	57.2	46.94%	34,492	547.631	352	193,728	499.873	629	29.27%	336,076	485.022		141.948	
Other														
NO <sub>x</sub>	0.22	0.18%	1,170	4.829	0	2,990	5.656	0	0.02%	1,740	3.435		0.001	
NMOG	0.22	0.18%	0.370	1.527	0	0.940	1.778	0	0.02%	0.550	1.086		0.000	
CH <sub>4</sub>	0.22	0.18%	0.333	1.374	0	0.846	1.600	0	0.02%	0.495	0.977		0.000	
CO	0.22	0.18%	0.180	0.743	0	0.460	0.870	0	0.02%	0.260	0.513		0.000	
CO <sub>2</sub>	0.22	0.18%	117,333	484.267	0	290	547.953	0	0.02%	168.667	332.933		0.0712	
Total														
NO <sub>x</sub>	122	100.00%	97,687	0.728	986	546,855	0.503	2,150	100.00%	973,872	0.411		0.411	
NMOG	122	100.00%	4,065	0.030	986	30,445	0.028	2,150	100.00%	54,071	0.023		0.023	
CH <sub>4</sub>	122	100.00%	3,659	0.027	986	27,401	0.025	2,150	100.00%	48,664	0.021		0.021	
CO	122	100.00%	15,134	0.113	986	113,042	0.104	2,150	100.00%	222,430	0.094		0.094	
CO <sub>2</sub>	122	100.00%	73,102	544.793	986	582,039	535.787	2,150	100.00%	1,195,073	504.760		504.760	

Table 5-38. South Coast Air Basin utility emissions related to EV charging — 95/5 charging

40% Distribution, 95/5 Charging, 0.35 kWh/mi											
2000				2005				2010			
Total SCAB	GWh	% Energy	Tons	g/kWh	GWh	Tons	g/kWh	GWh	% Energy	Tons	g/kWh
NO <sub>x</sub>	34	27.63%	7.378	0.199	456.70	34.020	0.068	1,240	57.74%	97.583	0.071
NMOG	34	27.63%	0.799	0.022	456.70	7.512	0.015	1,240	57.74%	28.244	0.021
CH <sub>4</sub>	34	27.63%	0.719	0.019	456.70	6.761	0.013	1,240	57.74%	25.420	0.011
CO	34	27.63%	4.186	0.113	456.70	32.682	0.065	1,240	57.74%	96.602	0.041
CO <sub>2</sub>	34	27.63%	17.673	477.146	456.70	230.322	457.918	1,240	57.74%	655,222	276,974
In-State, Non-SCAB											
NO <sub>x</sub>	34	28.15%	19.589	0.519	197.77	80.894	0.371	384	17.86%	149,413	0.354
NMOG	34	28.15%	3.010	0.080	197.77	17.099	0.079	384	17.86%	26.364	0.062
CH <sub>4</sub>	34	28.15%	11.472	0.304	197.77	62.287	0.286	384	17.86%	23.728	0.056
CO	34	28.15%	11.472	0.304	197.77	62.287	0.286	384	17.86%	99,000	0.234
CO <sub>2</sub>	34	28.15%	19,019	504.109	197.77	110,359	506.673	384	17.86%	207,588	491,435
Out-of-State, U.S.											
NO <sub>x</sub>	53	43.95%	81.240	1.379	330.33	469.280	1.290	524	24.38%	704,320	1.221
NMOG	53	43.95%	0.776	0.013	330.33	4.786	0.013	524	24.38%	7.538	0.013
CH <sub>4</sub>	53	43.95%	0.698	0.012	330.33	4.307	0.012	524	24.38%	6.784	0.012
CO	53	43.95%	2.204	0.037	330.33	12.880	0.035	524	24.38%	17,278	0.030
CO <sub>2</sub>	53	43.95%	36,795	624.600	330.33	218,299	600.052	524	24.38%	332,999	577,360
Other											
NO <sub>x</sub>	0.33	0.27%	1.560	4.292	0.56	3.170	5.140	0.55	0.03%	1.430	2.361
NMOG	0.33	0.27%	0.500	1.376	0.56	1.000	1.621	0.55	0.03%	0.460	0.759
CH <sub>4</sub>	0.33	0.27%	0.450	1.238	0.56	0.900	1.459	0.55	0.03%	0.414	0.683
CO	0.33	0.27%	0.240	0.660	0.56	0.490	0.794	0.55	0.03%	0.400	0.660
CO <sub>2</sub>	0.33	0.27%	154.000	423.733	0.56	308.000	499.400	0.55	0.03%	139	230.027
Total											
NO <sub>x</sub>	122	100.00%	109,767	0.819	985	587,364	0.541	2,148	100.00%	952,746	0.403
NMOG	122	100.00%	5.086	0.038	985	30,397	0.028	2,148	100.00%	62,606	0.026
CH <sub>4</sub>	122	100.00%	13,340	0.100	985	74,255	0.068	2,148	100.00%	56,346	0.024
CO	122	100.00%	18,102	0.135	985	108,339	0.100	2,148	100.00%	213,280	0.090
CO <sub>2</sub>	122	100.00%	73,641	549.395	985	559,288	515.376	2,148	100.00%	1,195,949	505.549

The ELFIN runs represent the average emissions from power plants associated with new power generation for EVs. However, the model does not take into account RECLAIM which would actually cap NO<sub>x</sub> emissions beyond the year 2010 as discussed previously.

Figure 5-16 shows a projection of energy demand in California for light-, medium-, and heavy-duty EVs (total assumed vehicle populations of 2,100,000, 73,000, and 450 respectively). These power demand assumptions are based on the EV population growth shown in Figure 5-17 (based on 2 percent EV sales in 1998 ramping up to 10 percent sales by 2003) (the heavy-duty vehicles are a small fraction that does not show up in Figure 5-17). The energy consumption is based in 0.2 kWh/mi, 0.4 kWh/mi, and 2 kWh/mi for light-, medium-, and heavy-duty vehicles. The particular assumptions on EV implementation and energy consumption result in a state-wide power demand of 10 GWh/day (3500 GWh/yr) beyond the year 2009. If 60 percent of the state's electric vehicles are placed in the South Coast Air Basin, the power demand (2100 GWh/yr) is consistent with the power demand in the ELFIN runs in Tables 5-37 and 5-38. The ELFIN model results depend entirely on the power demand. The power demand for Tables 5-37 and 5-38 was based on 3,138 million vehicle miles in 2010. (The model input assumed 0.35 kWh/mi or 0.38 kWh/mi with transmission losses.)

Power plant emissions were also considered for electricity used in fuel processing. Fuel processing plants such as oil refineries and ethanol plants operate around the clock, so the night time weighted power generation mix would not be applicable. Natural gas vehicles might be fueled with slow fill home compressors at night; however, it is not clear that home compression systems will be a large part of the market. ELFIN model results could be used to evaluate incremental power generation for fuel production facilities. However, determining whether the electricity demand for a fuel production facility is incremental or represents the average mix appears more subjective than the incremental assumption for EVs. Oil refineries and an ethanol plant are already operating in the South Coast Air Basin. If new fuel production facilities were built in the South Coast Air Basin, they might displace other industries; therefore, this study uses an average power generation mix for electric power consumption by fuel production facilities. Oil refineries rely on some degree of cogeneration for electric power; therefore, power generation emissions from refineries might be lower than those from out-of-state generation. Electricity consumption represents a small fraction of the energy used for oil refining, so the same average power generation mix was used for refineries.

### **5.3 FUEL STORAGE AND DISTRIBUTION**

Marketing and distribution of fuels involve their storage, transport, and transfer to the vehicle. These steps are described as Phases 4 through 8 in Section 4. The storage and distribution of liquid fuels is similar and considered in Section 5.3.1. Section 5.3.2 considers emissions from gaseous fuels and distribution losses for electricity.

#### **5.3.1 Liquid Fuel Storage and Distribution**

Gasoline, reformulated gasoline, diesel, LPG, methanol from natural gas, and ethanol will be stored in bulk storage tanks, both at production facilities and at product distribution terminals. Emissions from marketing and distribution of fuels primarily consist of fugitive emissions, such as breathing losses, vapor transfer losses, and spills during fuel transfers. California emission inventories exist for gasoline storage and distribution. Bulk storage emissions are determined by local AQMDs based on permit reporting for individual emission sources and formulas for specific tank

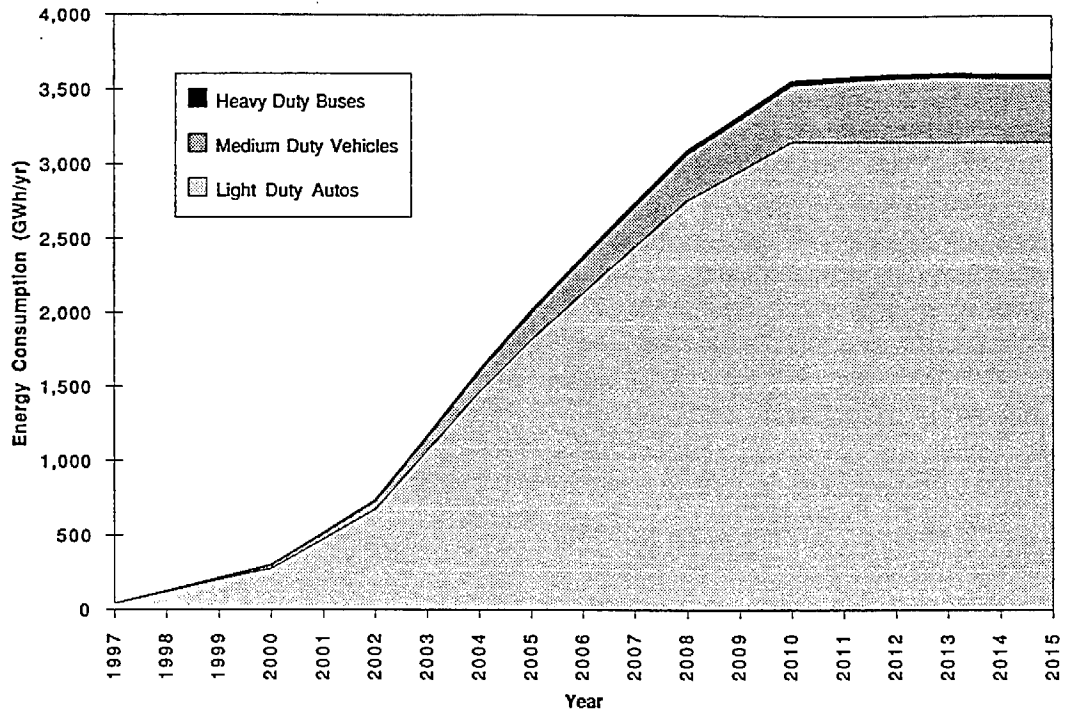


Figure 5-16. Projected energy consumption for EVs in California

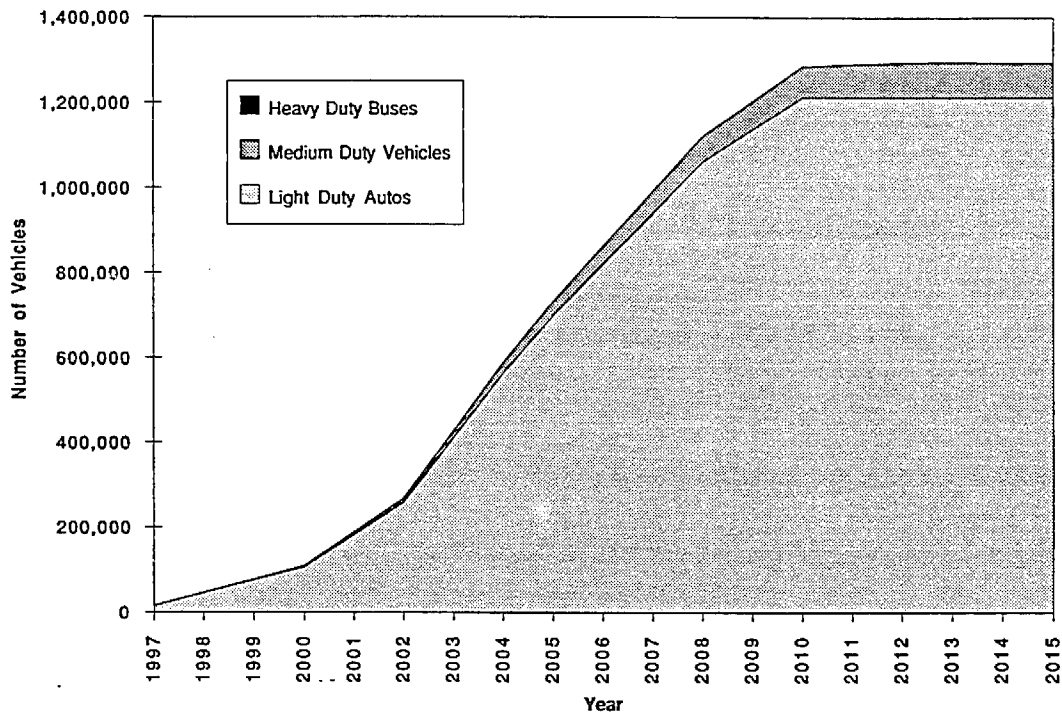


Figure 5-17. Projected California EV population (10% LDV sales)

configurations, throughput, and weather conditions (AP-42; and SCAQMD, 1994). ARB determines emissions from local fuel distribution which are the basis for the State's inventories (Asregadoo, 1992). This study examines the inventory values and also calculates emissions based on a specific set of assumptions.

#### **5.3.1.1 Local Fuel Storage and Delivery — Liquid Fuels**

This section describes the bulk storage and delivery of liquid fuels. Table 5-39 compares the emissions from bulk storage tanks based on the calculation technique in AP-42. The throughput is varied for current and future M100 and E100 tanks. The calculated value for a single gasoline tank on a per volume basis is about 0.15 times that of the 1990 SCAQMD gasoline inventory. Temperature and vapor pressure assumptions can cause some of this discrepancy. Also, the tank count and throughput in the inventory may effectively include several product storage tanks per gallon of finished gasoline. For example, refineries may have a tank for alykylate, one for FCC gasoline, another for MTBE, and so on. The per volume calculations in Table 5-39 are about two times as high as those calculated for a refinery permit applications (Chevron, 1994) which indicates that the throughput assumptions in Table 5-39 need to be reexamined.

Calculated gasoline vapor emissions were used as the estimate for fuel product storage (production Phase 6). The balance of the product storage tank emissions in the SCAQMD inventory were assigned to refinery storage. Refinery storage tanks contain numerous products and do not necessarily have the same level of throughput as those shown in Table 5-39. Production plant and terminal emissions for this study are shown in Table 5-40. Since these tanks represent a sizeable amount of emissions on an annual basis, vapor controls may be required. For Scenarios 3 and 4, a 90 percent reduction in emissions (reduction factor of 0.1) is assumed for liquid fuels except for diesel where its low vapor pressure would preclude vapor control requirements.

Emissions from the SCAQMD inventory were lower than those in other assessments which is not surprising given that the SCAQMD sources would have more extensive emission controls than those from other parts of the country. Calculated values for refinery tank storage, pipeline transfer, and bulk storage breathing were on balance lower than those in the inventory which probably reflects the more accurate and complete accounting of sources in the inventory. It should be noted that the most recent SCAQMD inventory includes methanol fugitive emissions with those of gasoline. However, the number of methanol vehicles in the 1990 inventory is minimal, and the inventory calculation is not affected by the small methanol vehicle population.

Current M100 emissions are based on calculations for an 8000-bbl floating roof tank. The throughput includes both chemical and vehicle methanol demand. Future methanol and ethanol emissions assume the same tank size and throughput as that of gasoline. Gasoline marketing may require more product tanks and transfer operations in order to produce different product blends. However, throughput per tank volume might be higher for gasoline than for methanol or ethanol.

#### **5.3.1.2 Local Fuel Distribution — Liquid Fuels**

This section describes the storage and distribution of liquid fuels at local service stations. These emissions consist of the following categories:

- Tank truck unloading spills

Table 5-39. Fugitive NMOG emissions from internal floating roof storage tanks

Fuel	Gasoline	RFG	Diesel	M100	M100	M85	E100	E100	E85
Year	All	All	All	1990	2010	All	1990	2010	All
RVP (psi)	8.40	6.80	0.03	4.63	4.63	7.20	8.70	8.70	7.50
TVP (psi)	7.60	6.10	0.02	3.50	3.50	6.30	1.70	1.70	6.40
Temp. (°F)	90	90	90	90	90	90	90	90	90
MW(vapor)	72	76	130	32	32	53	46	46	62
Tank Capacity (bbl)	50,000	50,000	50,000	8,000	50,000	50,000	3,000	50,000	50,000
Tank Diameter (ft)	100	100	100	45	100	100	30	100	100
Tank Height (ft)	36	36	36	30	36	36	24	36	36
Throughput (bbl/yr)	600,000	600,000	600,000	100,000	600,000	600,000	30,000	600,000	600,000
Throughput (gal/dy)	69,041	69,041	69,041	11,507	69,041	69,041	3,452	69,041	69,041
Turnover (day/tank)	30.42	30.42	30.42	29.20	30.42	30.42	36.50	30.42	30.42
Uncontrolled									
Emissions (lb/yr)	2,123	1,670	198	159	349	1,183	70	227	1,409
Emissions (g/gal)	0.0383	0.0301	0.0036	0.0172	0.0063	0.0213	0.0251	0.0041	0.0254

Table 5-40. NMOG emissions from bulk fuel terminals

Fuel	NMOG emissions (g/gal)		Scenario/Reduction Factor		
	Plant/Refinery	Bulk Terminal	2	3	4
Gasoline	0.19	0.0383	0.53	0.53	0.1
RFG	0.17	0.0301	0.53	0.53	0.1
Diesel	0.04	0.0036	1	1	1
M100, 1990	—	0.0172	—	—	—
M100, 2010	0.0063	0.0063	1	0.53	0.1
M85	—	0.0213	1	0.53	0.1
E100, 1990	0.0251	—	—	—	—
E100, 2010	0.0041	—	1	0.53	0.1

- Under ground tank filling — working losses
- Under ground tank breathing
- Vehicle fuel tank filling — working losses

Fuel is unloaded from a tank truck with vapor recover (referred to as Stage I). Most liquid fuel in California is stored in underground tanks. During the course of fuel storage, the vapor or ullage space in the tank expands and contracts as atmospheric pressure changes and fuel temperature changes. The fuel temperature remains almost constant in underground tanks. Fuel is dispensed to vehicles with a vapor recover hose system (Stage II vapor recovery).

The different stages of fuel distribution were observed to provide insight for this project. There are no significant differences in the unloading of gasoline or alcohol fuels. Fuel unloading at service stations is performed by the tank truck operator who may be an oil company employee or work for an independent company. Unloading is accomplished with appropriate precautions for safety and minimizing emissions. Fuel and vapor transfer hoses are connected from the storage tank to the truck. The truck carries its own fuel transfer hoses and an assortment of fittings for connection to the underground tank. After verifying the remaining tank volume with a dipstick measurement, the truck operator initiates the gravity fed unloading operation. When the fuel transfer is completed, the hoses are returned back to the tank truck. There is still a considerable volume of fuel in the fuel transfer hose (about a 4-inch inner diameter). The truck operator disconnects the hose from the truck tank and drains the remaining fuel in the bottom of the hose into the underground storage tank by lifting the hose into the air and moving the elevated section towards the connection at the underground tank. The hose is then disconnected and stored on the truck. During several such fueling operations, about 250 mL of fuel was observed spilling out of the hose as it was placed back into its holding tube on the truck. It was estimated that the volume from gasoline spills is about 180 g for an 8000-gallon fuel load, or 0.023 g/gal (0.05 lb/1000 gal). While this quantity is based on a casual observations, it provides some quantification of a small source that is not explicitly counted in the inventory. It is difficult to spill no fuel during hose transfers since the inner wall of

the transfer hose is covered with fuel as indicated by hooks on some tanker trucks for drying clean up rags.

An even smaller amount of fuel may remain on the hose surface and evaporate later. Transfer spills were estimated by Lyons to be 0.07 lb/1000 gal. The emission estimate was revised downward to reflect the times when no fuel is spilled. Even if truck transfers result in fewer spills, this rough estimate indicates that truck transfer spills are not a major category.

WSPA indicates that truck transfer is intended to be a no spill operation. Drivers are instructed to drain the hose into the tank before placing it back on the truck. These observations were atypical. Catch drains at the top of underground tanks would also capture some spilled fuel if it dripped from the tank connection. However, some wet hose losses are inevitable. The thin layer of fuel in the hose will result in some drips and evaporation. It should be pointed out that the volumes used in this study are based on rough estimates and do not reflect a large sample. Furthermore, liquid spill volumes are difficult to measure.

Service station fueling practices were also observed to evaluate vehicle fueling. The dispensers at eight fuel stations were polled to determine the amount of fuel dispensed per fueling event. Most fuel dispensers indicate the amount of fuel last dispensed until the dispenser is reset at the start of the next fueling operation. One dispenser type cleared all of its fuel readings immediately after the fueling event and therefore did not provide data. The amount of fuel dispensed ranged from one half to 18 gallons with an average of 8 gallons. The volume of fuel dispensed is important in determining emissions that depend on the number of fueling events rather than fuel volume. Various vapor recover nozzle types are used at service stations in California. At self service stations, the vehicle driver dispenses the fuel. Most customers select the self service option which results in a lower fuel price. While most vehicle operations are successful with little fuel spilled from the nozzle, occasionally a significant quantity of fuel is spilled. Fuel spills from vehicle refueling were evaluated by ARB (Morgester, 1992). This paper estimated spills from small drips as well as large refueler error type accidents. The average fuel spill size was estimated to be 0.7 lb/1000 gal. Another ARB study estimates this value at 0.42 lb/1000 gal. An API study estimated spill volumes at 0.31 lb/1000 gal.

Spill factors of 0.7, 0.7, 0.42, and 0.31 lb/1000 gal were used for Scenarios 1, 2, 3, and 4 respectively. From the ARB study, it appears that the role of large accidental spills is quite variable. Also, as vehicle fuel economy improves, fuel tank size will decrease. Thus, the average volume of fuel dispensed will decrease and the average volume of fuel spilled will increase. This suggests that the 0.31 lb/1000 gal value might be adjusted upward by about 20 percent. Other factors such as vacuum assist vapor recovery and on-board vapor controls could reduce spill volume.

### **Inventory Emission Factors**

ARB determines emission factors from gasoline dispensing facilities (Asregadoo, 1992). The emission sources are broken into the categories shown in Table 5-41. Each category has a Category Emission Source (CES) code and emission factor for uncontrolled and controlled fueling operations. Spills from tank truck unloading are not explicitly accounted for; however, they may be implicitly included in an adjustment factor. Emissions from working losses and tank breathing are based on a combination of ideal gas law calculations in AP-42 and ARB's certification testing results. The current document shows 0.7 lb/1000 gal for fuel spillage. All of the spilled liquid will evaporate from

**Table 5-41. ARB emission factors for gasoline dispensing facilities**

CES	Description	Emission Factor (lb/1000 gal)		Emission Factor (g/gal)		Control Factor (%)
		Without Control	With Control	Without Control	With Control	
46532	Under ground tank working loss	9.5	0.475	4.313	0.216	95
46577	Under ground tank breathing loss	1.0	0.1	0.454	0.0454	90
46540	Vehicle refueling vapor displacement	10.0	0.5	4.54	0.227	95
46565	Vehicle refueling Spillage	0.7	0.7	0.318	0.318	0
Total	—	21.2	1.775	9.625	0.806	—

the concrete surface at service stations. Uncontrolled emissions are determined from the gas concentration in the tank ullage space.

Since the values in this study will be compared to emission inventories it is important to understand how inventories are developed and how those values compare to this study. Emission inventories are based on the mix of controlled and uncontrolled sources and estimate of the number of operations with defective emission controls. Stage I and Stage II vapor recovery are considered to be 95 percent effective; so controlled emissions are 5 percent of the uncontrolled value. Breathing losses from underground tanks are estimated at 10 percent of the uncontrolled value if both Stage I and Stage II controls are in effect. No controls are assumed for spillage. The mix between controlled and uncontrolled service stations varies across the State. Some smaller operations have been exempt from Stage II vapor recovery requirements. Stage I vapor recovery is always used. In addition to reducing emissions, it returns vapor product to the refinery and provides for safer operations.

Statewide inventories are comprised of emission factors that are adjusted for malfunctions or failures in the vapor recovery system or defect rate. For example, emissions from vehicle refueling vapor displacement or working losses with 95-percent control and a 4-percent defect rate would be the following:

$$\text{Emissions (lb/1000 gal)} = 10 \times 0.96 \times 0.05 + 10 \times 0.04 = 0.88 \quad (5-5)$$

The defect rate has a profound effect on the overall emission estimate and was incorporated into the vapor emissions in this study. Emission inventories include control factors that vary by year and also defect rates that vary by year. Since these numbers are not readily accessible at this time, distribution emissions were based on the assumptions shown in Table 5-42. The control factors and defect rates

**Table 5-42. Emission control assumptions for local fuel distribution**

CES	Description	Emission Factor (g/gal)			SCAQMD 1990 Inventory (g/gal)	SMAQMD 1999 Inventory (g/gal)
		With Control	Assumed Defect Rate in This Study	With Defect Rate or No Controls		
46532	Underground tank working loss	0.215	0%	0.215	0.3954	0.305
46577	Underground tank breathing loss	0.045	0%	0.045	0.0633	0.063
46540	Vehicle refueling vapor displacement	0.227	5%	0.443	0.6332	0.534
46565	Vehicle refueling spillage	0.318	—	0.318	0.318	0.318
Total	—	0.805	—	1.199	1.410	1.220

were applied uniformly to all liquid fuels. The baseline uncontrolled emissions were then modeled from the fuel's vapor pressure and vapor molecular weight. The resulting emissions estimate is compared to the emissions inventory for SCAQMD.

The higher effective uncontrolled/defect rates in the inventory reflect uncontrolled sources such as pleasure boat fuelings or different assumptions on the defect rate. These uncontrolled sources do not reflect incremental gasoline that would be displaced by alternative fuels, so uncontrolled rates of 0 percent were used for underground tank working and breathing losses. Data from one fueling station measurement indicate that breathing losses are lower than those shown in Table 5-42 (Shearer, 1977).

Improving upon the 95 percent control effectiveness does not appear likely with Stage II controls. The basis for the defect rate is unclear. Actual defect rates may be higher or lower than the values used in emission inventories. Emission inventories also take into account uncontrolled fueling stations which are not the focus of this study. The higher inventory value in Table 5-42 reflects defect rates, uncontrolled sources, and emission controls. Future refueling emissions might be lower due to reduced Stage 2 failures with vacuum assist nozzles and other fueling equipment; however, the extent of such reductions if any has not been quantified.

Distribution emissions are estimated from the emission control assumptions in Table 5-42, and the fuel's properties. An underlying assumption is that the control effectiveness is equal for all fuels. There might be greater variation in control effectiveness for small volume fuel distribution (perhaps higher or lower) and underground tank breathing losses would depend upon the fueling station throughput. The number of vehicles per station will vary as more alcohol-fueled vehicles are introduced into the State. A total vehicle to fueling station ratio of about 2500 currently exists for gasoline-fueled vehicles. Many of these stations have multiple tanks. As alcohol-fueled vehicles are introduced, the ratio of vehicles to fuel tanks will approach the ratio for gasoline tanks. Therefore,

differences in breathing losses due to differences in throughput will be small on a pound per day basis during an alcohol vehicle transition and would become negligible for a larger fleet of alcohol-fueled vehicles. Second order effects on breathing losses (per gallon) would depend on whether gasoline tanks are decommissioned if alternative-fueled cars displace gasoline-fueled cars. Given equivalent assumptions on emission control, distribution emissions depend on fuel vapor pressure and vapor molecular weight. Scenario 4 includes a downward adjustment by 50 percent of service station vapor losses to reflect reduced emissions from storage tank breathing and a potentially lower defect rate for Stage II control.

## Vehicle Fueling Spillage

Some fuel spills during fueling operations. The API study does not indicate an increase in spillage from self service fueling and topping off. Spilled fuel evaporates completely and is counted as fugitive emissions. An exception is diesel which has such a low vapor pressure that it is expected at least half of the fuel will not evaporate, but will behave similar to engine oil drips. Spilled fuel is particularly interesting because the ozone potential of liquid fuels are higher than those of their vapors (with the exception of pure compounds). ARB's emission factor for refueling spillage is 0.7 lb/1000 gal (0.318 g/gal), and is based on a value in AP-42. A recent study by ARB resulted in a lower spillage rate of 0.42 lb/1000 gal; however, this value is not used in inventory calculations. Given the effect of infrequent large spills on the average spill rate, both spill rates were used in this study.

Spillage rates for other liquid fuels were based on the premise that the average spill volume remains constant. Several fuel stations were surveyed and an average gasoline fill volume of 8.8 gallons was observed. This is consistent with the 9.2 gal observed by Morgester. An increase in fuel tank capacity for alternative-fueled vehicles is expected, but not enough to completely make up for the reduction in energy content. Table 5-43 shows the estimated average fill volume for the fuels in this study. Gaseous fuels are also shown for comparison. Since the fuels have different densities, the spill mass was adjusted for each fuel. Table 5-43 shows the liquid fuel spill volumes based on the 0.7 lb/1000 gal factor. Emissions in Scenarios 3 and 4 are based on a gasoline spillage factor of 0.42 and 0.31 lb/1000 gal.

The fill volume of FFV fuel tanks was adjusted upward in proportion to the ratio of FFV and conventional gasoline fuel tanks (20 gal/16 gal). Some FFVs may not have increased tank capacity; however, a 20-percent volume increase reflects actual experience. Diesel fuel tanks should also be the same size as gasoline tanks since car manufacturers will not bother to reduce tank capacity to achieve the same range as gasoline. Larger refill volumes were also estimated for M100, E100, LPG, LNG, and LH<sub>2</sub> with larger fuel tanks. However, the energy content of these fuels is sufficiently lower than gasoline to result in fewer Btus of fuel in the alternative-fuel tanks than that of the gasoline tank. For 2010, one might expect smaller fuel tanks for more fuel-efficient vehicles. These smaller tanks would result in larger fuel spillage per refueling and would provide further justification for a spillage factor of 0.7 lb/1000 gal. Also, the baseline 9-gallon gasoline fill volume was based on current vehicle fleet fueling observations. The current fleet has a higher energy consumption and larger fuel tank size than the incremental new car. Thus, for new future cars, as fuel tank size decreases the average volume of fuel spilled per quantity dispensed will increase. During fueling and fuel transfer processes, liquefied gases or pressurized gas can leak from the trapped volume between fittings. Trapped volumes were estimated for gaseous fuel transfers and vehicle fuelings, and are discussed in Section 5.3.3.

**Table 5-43. Vehicle fuel spillage parameters**

Fuel	Average Tank Fill (gal)	Spill Volume		Spill Rate (g/gal)	Scenario/Reduction Factor		
		(mL/fill)	(mL/gal)		2	3	4
Gasoline, RFG	9	4.0	0.44	0.318	1	0.6	0.44
Diesel	9	4.0	0.44	0.38	1	0.6	0.44
M85	11	4.0	0.36	0.288	1	0.6	0.44
E85	11	4.0	0.36	0.288	1	0.6	0.44
M100	15	4.0	0.26	0.211	1	0.6	0.44
CNG	1000 scf	5.0	0.5	0.09	0.8	0.6	0.4
LNG	14	3.0	0.21	0.09	1	1	1
LPG	12	2.0	0.17	0.08	1	1	1
LH <sub>2</sub>	7 lb	3.0	0.43	0.03	1	1	1

### Vapor Space NMOG Mass

Vapor emissions in this study are determined from modeled vapor concentrations. The fuel temperature used to determine vapor concentrations was selected to be consistent with ARB's inventory for fueling station emissions. Ozone potential was determined from the specific reactivity of vapors that was determined from speciation analysis. The measured specific reactivity was close to that estimated in Mobil's model as discussed in Section 3.

The vapor concentration in the tank vapor space is the basis for fuel transfer emission calculations in AP-42 and provides insight into the temperature conditions for vapor emissions. Vapor space concentrations are modeled from equilibrium vapor concentration. The extent of vapor saturation is reflected by the saturation factor. For vapor recovery systems a saturation factor of 1.0 or completely saturated vapor is assumed in AP-42. ARB (Asregadoo, 1992) bases the vapor space concentration on test data. The vapor space gas concentration represents the uncontrolled emissions from tank truck unloading (underground tank working losses), and vehicle tank working losses.

Vapor space concentrations from liquid fuels were estimated from the ideal gas law. Given a molar volume of 379.6 ft<sup>3</sup>/lb mole at 60°F, the equilibrium vapor ( $V_e$ ) in a tank head space can be calculated from the following equation:

$$V_e \text{ (lb/gal)} = MW \text{ (lb/mol)} \times \text{lbmol}/379.6 \text{ ft}^3 \times 0.1337 \text{ ft}^3/\text{gal} \quad (5-6)$$

$$\times TVP/14.7 \text{ psi} \times 520^\circ\text{F}/T$$

Where:

$T$  = Gas and liquid temperature ( $^\circ\text{R}$ )  
 $TVP$  = True vapor pressure (psi) at the equilibrium temperature

Table 5-44 shows the vapor space concentrations from various liquid fuels. Since the ARB inventory is based on test data that represents a range of gas temperatures and actual saturation conditions, a representative condition was modeled that reflects the inventory value. An effective fuel temperature was estimated for the ARB inventory values. The values in the top portion of Table 5-44 illustrate what temperature conditions would yield vapor concentrations that are consistent with the ARB inventory values (9.5, 1.0, and 10.0 lb/1000 gal for uncontrolled NMOG vapor mass). The 10 lb/1000 gal emission factor can then be calculated from a temperature of 80°F, TVP of 6.2 psi, and vapor molecular weight of 70. A higher molecular weight corresponds to lower RVP gasolines since they contain less butane (MW=58). One could ignore the inventory data and simply project vapor emissions based on an assessment of vapor temperatures. This approach could be used to parametrically evaluate the effect of temperature on fuel cycle emissions, but was not performed in this study. All of the emphasis was placed on comparison of emissions in the context of the State inventory values.

Vapor concentrations (uncontrolled NMOG vapor mass) for this study were determined from equilibrium vapor densities that correspond to 70°F for underground tank vapors, and 80°F for vehicle fuel tank vapors. Actual vehicle vapor temperatures can be much higher. The equilibrium vapor densities were determined from Mobil's model for Phase 2 gasoline, M85 (blended to meet 7.2 RVP), and E85. Equation 5-6 yields similar results if the TVP is projected from the fuel's RVP. The vapor density for M100 and conventional gasoline were estimated from Equation 5-6.

The same temperature conditions can then be applied to a range of liquid fuels to generate vapor space concentrations or uncontrolled emission estimates that are consistent with California inventories. This effectively results in an equivalent equilibrium temperature that reflects the actual range of fuel temperatures and saturation conditions that correspond to test data. The underlying assumption with this approach is that the inventory data is based on a broad range of conditions and reflects the suitable conditions. Also shown in Table 5-44 are the vapor densities that would correspond to underground storage at 60°F and vehicle fuel storage at 100°F. These values were not used further in this study but provide insight into the effect of temperature on ozone potential.

The inventory values reflect an equivalent equilibrium temperature of about 75°F for storage tank vapors. This value appears higher than what might be expected for soil temperatures. The effective temperature for vehicle tank vapors is 80°F which appears reasonable and agrees with fuel vapor and liquid measurements. Since this study is aimed at evaluating summer conditions these temperatures were used for estimating uncontrolled emissions. The baseline 8.4 RVP gasoline was used to represent summer gasoline. This is different than the fuel used in the inventory which reflects year round fueling. The effective temperature for the inventory was first calculated from the average

Table 5-44. Evaporative emissions from local fuel distribution

Fuel/ Emission category	RVP	Effective Temperature (°F)	Uncontrolled NMOG Vapor Mass		Controlled NMOG Vapor (g/gal) *		TVP (psi)	MW (g/mol)
			(g/gal)	(lb/1000gal)	w. Control	& Defect		
AP-42 sample calculation	10	80	4.56	10.0	0.228	--	6.6	66
ARB UG tank working loss	9.2	71	4.30	9.5	0.215	0.2152	5.90	68.5
ARB UG tank breathing loss	9.2	71	0.454	1.0	0.045	0.0454	5.9	68.5
ARB vehicle working loss	9.2	76	4.55	10.0	0.227	0.4433	6.29	68.5
Values for fuel cycle study <sup>b</sup>								
Gasoline UG tank working loss	8.4	70	3.48	7.66	0.1738	0.1738	1.82	0.3163
Gasoline UG tank breathing loss	8.4	70	0.35	0.77	0.0348	0.0348	1.82	0.0633
Gasoline vehicle working loss	8.4	80	4.23	9.31	0.2114	0.4123	1.82	0.7504
Gasoline UG tank working loss	8.4	60	2.83	6.23	0.1414	0.1414	1.82	0.2574
Gasoline UG tank breathing loss	8.4	60	0.28	0.62	0.0283	0.0283	1.82	0.0515
Gasoline vehicle working loss	8.4	100	6.10	13.44	0.3051	0.5950	1.82	1.0828
Phase 2 UG tank working loss	6.8	70	3.04	6.70	0.1520	0.1520	1.65	0.2508
Phase 2 UG tank breathing loss	6.8	70	0.30	0.67	0.0304	0.0304	1.65	0.0502
Phase 2 vehicle working loss	6.8	80	3.68	8.11	0.1840	0.3588	1.65	0.5920
Phase 2 UG tank working loss	6.8	60	2.49	5.48	0.1245	0.1245	1.65	0.2054
Phase 2 UG tank breathing loss	6.8	60	0.25	0.55	0.0249	0.0249	1.65	0.0411
Phase 2 vehicle working loss	6.8	100	5.27	11.61	0.2635	0.5138	1.65	0.8478
Diesel UG tank working loss	0.03	70	0.012	0.03	0.0125	0.0125	0.511	0.0064
Diesel UG tank breathing loss	0.03	70	0.001	0.00	0.0012	0.0012	0.511	0.0006
Diesel vehicle working loss	0.03	80	0.016	0.04	0.0163	0.0163	0.511	0.0083
Diesel UG tank working loss	0.03	60	0.010	0.02	0.0105	0.0105	0.511	0.0053
Diesel UG tank breathing loss	0.03	60	0.001	0.00	0.0010	0.0010	0.511	0.0005
Diesel vehicle working loss	0.03	100	0.029	0.06	0.0289	0.0289	0.511	0.0148

\* Working loss control factor = 95%, breathing control factor = 90%, Defect rate = 5% for vehicle losses

<sup>b</sup> UG=Underground tank. UG tank losses are based on 70 F values. Vehicle losses are based on 80 F values. Emissions are also shown for 60 and 100 F for comparison but not used in this study. Vapor emissions are reduced 50% in Scenario 4.

Distvap3.xls

Table 5-44. Evaporative emissions from local fuel distribution (concluded)

Fuel/ Emission category	RVP	Effective Temperature (°F)	Uncontrolled NMOG Vapor Mass a		Controlled NMOG Vapor (g/gal) *		Ozone Potential	
			(g/gal)	(lb/1000gal)	w. Control	& Defect	(gO <sub>3</sub> /g)	(gO <sub>3</sub> /gal)
M85 UG tank working loss	7.2	70	1.98	4.36	0.0990	0.0990	1.21	0.1198
M85 UG tank breathing loss	7.2	70	0.20	0.44	0.0198	0.0198	1.21	0.0240
M85 vehicle working loss	7.2	80	2.44	5.37	0.1220	0.2379	1.21	0.2879
M85 UG tank working loss	7.2	60	1.60	3.52	0.0800	0.0800	1.21	0.0968
M85 UG tank breathing loss	7.2	60	0.16	0.35	0.0160	0.0160	1.21	0.0194
M85 vehicle working loss	7.2	100	3.62	7.97	0.1810	0.3530	1.21	0.4271
E85 UG tank working loss	6.8	70	2.69	5.93	0.1346	0.1346	1.24	0.1670
E85 UG tank breathing loss	6.8	70	0.27	0.59	0.0269	0.0269	1.24	0.0334
E85 vehicle working loss	6.8	80	3.21	7.07	0.1605	0.3129	1.24	0.3880
E85 UG tank working loss	6.8	60	2.69	5.93	0.1346	0.1346	1.24	0.1670
E85 UG tank breathing loss	6.8	60	0.27	0.59	0.0135	0.0135	1.24	0.0167
E85 vehicle working loss	6.8	100	2.69	5.93	0.1346	0.2625	1.24	0.3256
M100 UG tank working loss	4.5	70	0.683	1.50	0.0341	0.0341	0.56	0.0191
M100 UG tank breathing loss	4.5	70	0.068	0.15	0.0068	0.0068	0.56	0.0038
M100 vehicle working loss	4.5	80	0.871	1.92	0.0436	0.0849	0.56	0.0476
M100 UG tank working loss	4.5	60	0.491	1.08	0.0246	0.0246	0.56	0.0138
M100 UG tank breathing loss	4.5	60	0.049	0.11	0.0049	0.0049	0.56	0.0028
M100 vehicle working loss	4.5	100	1.462	3.22	0.0731	0.1426	0.56	0.0798
E100 UG tank working loss	2.3	70	0.442	0.97	0.0221	0.0221	1.34	0.0296
E100 UG tank breathing loss	2.3	70	0.044	0.10	0.0044	0.0044	1.34	0.0059
E100 vehicle working loss	2.3	80	0.578	1.27	0.0289	0.0564	1.34	0.0755

\* Working loss control factor = 95%, breathing control factor = 90%, Defect rate = 5% for vehicle losses

Distvap3.xls

RVP. An effective summer and winter temperatures were then determined. The summertime temperatures for vehicle fueling were based on ARB fuel tank measurements. The wintertime temperature is consistent with the overall inventory. This approach, while somewhat arbitrary, is based on reasonable temperature values and provides a basis for understanding the differences in emission factors used in this study and those in the State inventory.

Table 5-44 shows the vapor space NMOG for conventional gasoline, Phase 2 gasoline, M85, M100, E85, and E100. Vapor molecular weights for gasoline and M85 blends were based on the Mobil model and are consistent with ARB's data to the extent that the temperature was in equilibrium and the fuel did not weather. M100 and E100 vapors have the same composition as the liquid. Data from drum vapors represents storage tank vapors and data from a vehicle tank was used for vehicle tank vapors. Vapor molecular weights did vary over the range of tank temperatures. Composition was affected by the temperature equilibrium. Weathering substantially affected the E85 vapors in the vehicle tank data. The net effect on specific reactivity is negligible since the MIR values for ethanol and butane are almost identical. A reduced RVP for E85 is therefore assumed. The impact on running losses and evaporative emissions should be considered; however, if compliance with evaporative standards is assumed, there should be no effect of fuel weathering. Table 5-44 also shows tank truck distribution emissions for liquid fuels. These emissions take into account vapor recovery effectiveness and a 5 percent defect rate for Stage II emission controls as indicated in Tables 5-41 and 5-42. This combination of control effectiveness and defect rates will yield an emission factor lower than that used in State inventories. However, the inventories include uncontrolled fuel dispensing which is not relevant to this study.

The MIR ozone potential is calculated from the specific reactivities in Section 3 and the NMOG emissions (controlled emissions with defect rate) in Table 5-44. The lower RVP of Phase 2 gasoline and lower specific reactivity of vapors contributes to a lower ozone potential Phase 2 gasoline. While splash blended M85 has a higher RVP than that of Phase 2 gasoline, the molecular weight and specific reactivity of M85 vapors are both about 30 percent lower than those of Phase 2 gasoline. The net result is a 60 percent reduction in the ozone potential of vapors. A vapor space model was used to evaluate the reactivity of M85 tank vapors (Auto/Oil, July 1994). These results showed only an 8 percent reduction in specific reactivity. The lower specific reactivity of the M85 vapors appears to be due to a reduction in light olefins in the M85 vapor ( $C_5$  through  $C_7$ , eg. 2-methyl-2-butene) without a reduction in light paraffins relative to Phase 2 vapor. The comparative reactivity of the vapor components warrants further analysis.

The ozone potential of M100, E85, and E100 were considerably lower than those of gasolines and M85. The vapor pressures for these fuels are much lower than those for gasoline. Cold starting would be an issue with these fuels in conventional FFVs. However, they could be utilized in alternative engine designs such as direct injection engines. The results for E85 reflect blending with Phase 2 gasoline and butane to achieve an RVP of 6.5. Blending butane into E85 at the refinery increases the vapor pressure and the butane content of the vapors. Butane comprises about 56 percent of the vapor space of splash blended E85. The speciation data and equilibrium modeling were based on E85 with and RVP of 7.5. This analysis assumed a lower RVP and no change in ozone potential. (The MIR of butane is 1.02 which is very close to that of E85 vapors. Therefore, reducing the RVP by reducing butane content would not have a major impact on ozone potential.)

Vapor concentrations were measured for the fuels in this study. The vapor concentrations presented in Section 3 depend upon the liquid and vapor temperature in the vehicle as well as the

ambient temperature. All of the tests were not performed simultaneously over the same temperature conditions. However, the speciation and corresponding molecular weight and ozone potential will vary less with temperature than the vapor concentration. Since the test conditions do not necessarily reflect the range of conditions in the State inventory, it was necessary to model the emissions to present a consistent basis for comparison. A comparison of test vapor concentrations to modeled vapor concentrations will be made later.

### 5.3.1.2 Alcohol Fuel Blending Approaches

Different approaches to blending alcohols were evaluated. These included the following options:

- Option A— Blend at bulk storage tank
- Option B — Blend in tank truck
- Option C — Blend pump at local service station
- Option D — Neat alcohol (M100, E100)

Each option results in different emissions. The properties of the fuel are also affected by the blending approach. Option A provides for the most accurate fuel mixing. The product fuel could be blended from volatility adjusted gasoline that results in an RVP of 7 psi.

Option A is the most feasible approach for E85 that is consistent with meeting a 6.5 psi RVP requirement through blending with butane. Butane could be blended in E85 storage tanks. Option A is assumed for M85 production from biomass as well as E85 in Scenarios 2, 3, and 4.

Product delivery to bulk storage tanks is assumed to be performed by pipeline for Option A. Pure methanol or ethanol are delivered to bulk storage tanks. The fuel is then transferred to a blending tank for mixing to produce M85 or E85. This option requires an additional storage tank for the fuel blending.

It is impractical to add butane directly to ethanol as vapor losses would occur if the fuel is not completely blended. Technological innovations could overcome the ethanol blending problem. For example, a premixing tank could be set up for blending butane with RFG. The RFG/butane mixture could be bottom filled into a truck containing E100 without generating substantial vapors. This system would have the advantage of finding a market for butane. However, the advantages of selling butane may not offset the negative aspects of developing a system to accommodate ethanol which is not part of the fuel terminal's sales. However, this scenario is based on a large enough ethanol demand to support pipeline shipments to Los Angeles. Such a large fueling infrastructure could certainly accommodate the equipment for butane blending.

Option B is the current fuel distribution approach that is used for M85. The fuel distribution for methanol from natural gas is based on option B. This approach requires an additional short tank truck trip from the gasoline terminal to the methanol terminal. There is also an additional fuel transfer made to the tank truck. Since RFG and methanol (or ethanol) are stored in separate storage terminals for this option, the evaporative emissions from bulk storage tanks corresponding to each component fuel were added in appropriate proportions (approximately 15:85). E85 is currently blended in tank trucks, so Scenario 1 is based on blending option B.

For option C, the methanol and gasoline fuels are delivered separately to underground storage tanks. With separately stored fuels, the fuel station can sell RFG, M85, and M100. M100 could be sold as a fuel for heavy-duty vehicles or advanced light-duty vehicles. A blend pump draws fuel from two tanks and meters methanol and gasoline in the proportions required to meet fuel specifications. The accuracy of the blend pump is likely to be less than that of either Option A or B. The level of accuracy of the blend pump approach needs to be evaluated further. Another option for onsite blending would be a blend tank. This approach would not require a complicated blending pump to blend M85 on demand and may be simpler to implement. The blend pump approach may not comply with the strictest interpretations of the M85 fuel specification. However, since it is likely that FFVs will operate on commingled blends, fuel specification could be modified to accommodate blend pump operation.

### **5.3.3 Gaseous Fuel Distribution**

Gaseous fuels considered in this study include CNG, LNG, LPG and hydrogen. CNG is produced across North America and transmitted to distribution companies (utilities) in California. Gas for CNG is compressed at local fuel stations. LNG is currently produced in Sacramento, California as a source of pure methane; however, most LNG used recently in vehicles has been shipped from Wyoming. LNG will probably be imported into California for some applications and new liquefiers may also be built. LPG for vehicle use is primarily produced from gas treatment facilities and shipped to California. LPG is also produced as a byproduct of oil refining. Hydrogen is produced from natural gas in several locations in the U.S including a liquefaction facility in Sacramento. Liquid hydrogen or  $LH_2$  was considered as the primary option for hydrogen use. This section covers fugitive emissions from bulk fuel transportation and local distribution as well as CNG compression energy requirements. Emissions from fuel hauling are proportional to distances traveled which are discussed in Section 5.1

#### **5.3.3.1 CNG Transmission and Distribution**

Natural gas is transported through pipelines with compressors that maintain a pressure ranging from 220 to 1100 psi. A typical distribution pressure is 800 psi. Natural gas that will be used to fuel NGVs will represent new supplies beyond current demand. This incremental gas will be transported from West Texas or Western Canada.

The compressor power, distance, and gas throughput for several pipeline projects was summarized by A.G.A. (A.G.A., 1993). The average energy use is 0.014 hp/Mmscf/d. Compression energy represented on a per mile basis ranged from 0.6 to 2 hp-hr/MMscf/mi with a weighted average of 0.9 hp-hr/MMscf/mi for Western States. Emissions from compressors are based on emission rates and transportation distances in Section 5.1. The emissions data base calculates emissions in g/1000 mi/100 scf. Compression energy usage is calculated in terms of a percentage of 1000 miles transported.

Local fueling stations can be configured in several ways which affects the amount of energy required for compression. Compression energy depends upon the compressor inlet pressure and the final outlet pressure. For light-duty CNG applications, we assume a 3000 psi vehicle storage system. In practice, slow fill requires compressor outlet pressures of about 3600 psi and fast fill systems require about 4000 psi compressor outlet. Compressor inlet pressures can vary from a slightly above atmospheric to 200 psi.

Many fueling systems must take gas from a low pressure supply line that is fractions of a psi above atmospheric since this is the operating regime for conventional gas meters. A four stage compressor with a pressure ratio of 4 to 5 in each stage will result in an outlet pressure of about 4000 psi. Local distribution lines often have 200 psi gas which would allow for a two stage compressor to be used. It is not anticipated that CNG fueling facilities will have access to higher pressure (800 psi) transmission lines.

Data on actual CNG compression energy requirements appear limited since most CNG compressors are not equipped with a dedicated electric meter. The Orange County Transportation Authority has a cascade fill system with a dedicated gas meter and an electric meter which provide an accurate value for actual compression energy requirements (Unnasch, 1993). This system uses low pressure gas and fills storage bottles with a fueling capacity of about 6000 scf over a 2 hour period. Such a system could support 3 cars per hour. Data on gas and electricity use result in compression energy (compression factor) of 1.2 to 1.4 kWh/scf.

Compression energy can also be calculated theoretically by assuming isentropic compression. The work for each compression stage would be:

$$W_i = m \times (P_o/P_i)^{(\gamma-1)/\gamma} \quad (5-7)$$

Where:

- $W_i$  = Work per compressor stage
- $m$  = Natural gas mass flow rate
- $(P_o/P_i)$  = Pressure ratio between stages (about 5)
- $\gamma$  = Adiabatic constant, ratio of specific heats at constant pressure and constant volume

This equation provides good correlation with actual experience. Data from an OCTA compressor system required about 10 percent more energy than the theoretical equation which is consistent with mechanical losses in efficiency. Compressor manufacturers also publish compression factors for their equipment. Larger capacity compressors are more efficient than smaller ~30-scfm units. The equation was used to project energy requirements for slow fill fueling and fueling with higher inlet pressure to the compressor.

Table 5-45 shows energy requirements for CNG compression. Different configurations in the table are based on the compression requirements for fast and slow fill. The trend in CNG vehicles is towards higher cylinder pressures. Total compression energy depends on both the inlet pressure as well as the final outlet pressure. CNG compression energy might increase with higher cylinder pressures; however, as the industry advances, more fueling sites should make the effort to take their gas from high pressure lines. Emissions associated with electricity generation for NGV compression correspond to the average emissions.

Leaks from CNG compressors are based on comments from compressor manufacturers. Leaks during fueling correspond to a 5-cc space between the fueling receptacle and vehicle. Gas at 3600 psi is vented to the atmosphere.

**Table 5-45. Natural gas compression energy**

Compressor Type	Fast Fill		Slow Fill	
	30 cfm 5 psi feed	300 cfm 50 psi feed	30 cfm 5 psi feed	300 cfm 50 psi feed
Compression energy (kWh/100 scf) <sup>a</sup>	1.4	0.7	1.2	0.6
Scenario 1 and 2 equipment mix. Average 1.2 kWh/100 scf.	80%	20%	80%	20%
	70%		30%	
Scenario 3 and 4 equipment mix. Average 1.0 kWh/100 scf.	60%	40%	60%	40%
	30%		70%	
Compressor leaks (gNMOG/100 scf) [Source code]	0.01 [C72.1]			

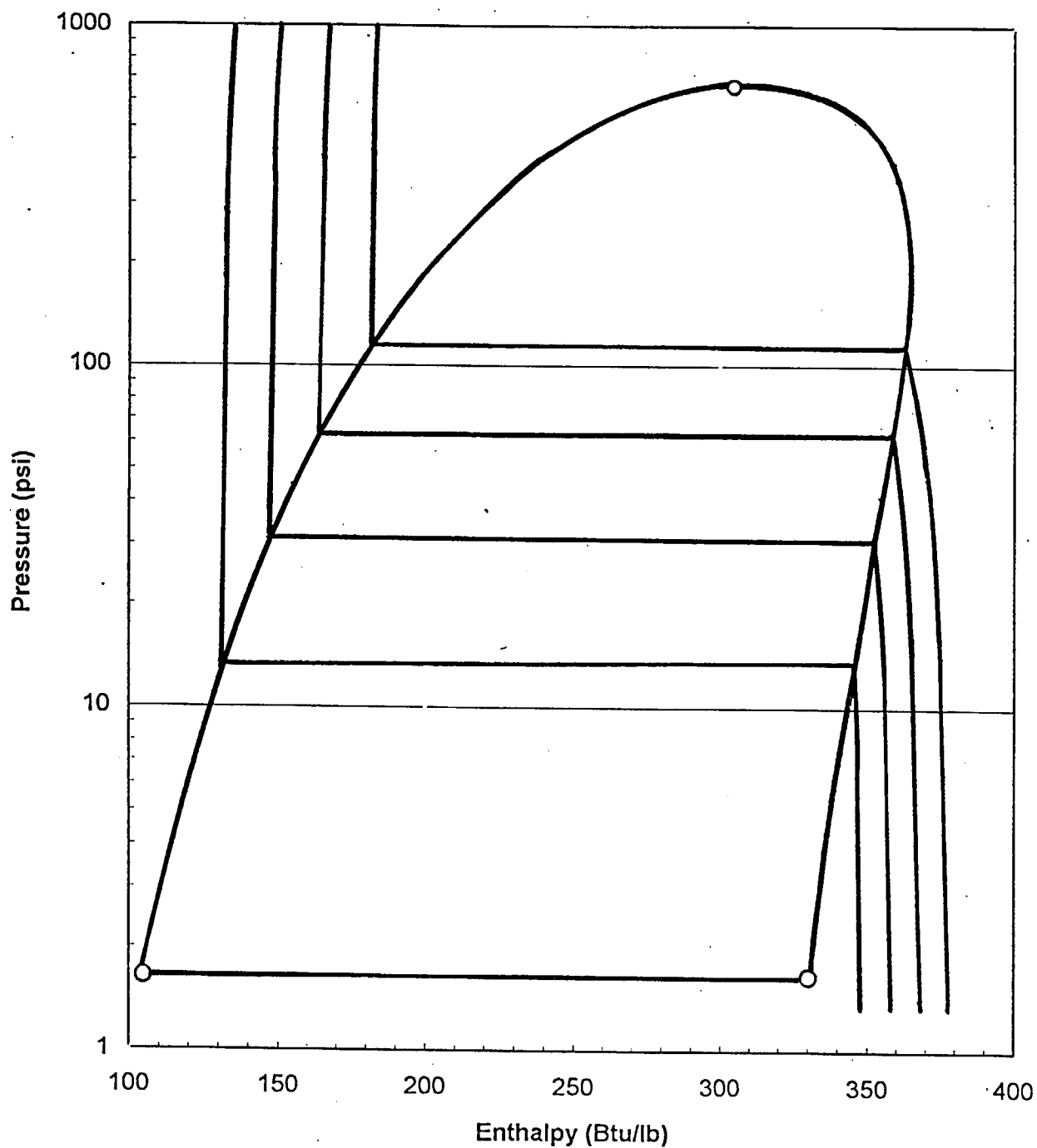
<sup>a</sup>1.2 kWh/100scf for Scenario 1 and 2, 1.0 kWh/100scf for Scenarios 3 and 4.

Measurements of a CNG fueling receptacle and vehicle fitting indicated trapped volume of 5 ml. CNG fittings that were examined made a seal in two steps. First, the fitting is connected to form a seal. A valve is then opened to release CNG into the vehicle tank. The higher pressure CNG flows through the vehicle tank fitting and check valve. After fueling, the valve is closed and fuel in the internal volume is released by opening a valve. This small volume of fuel is often routed away from the fueling station into the atmosphere. Fuel leakage is calculated from the gas density at 3600 psi (3000 psi for a slow fill system). This leaked fuel passes through a hose where it is routed away from the vehicle. New CNG fueling installations are equipped with a receiver tank that captures and recompresses the vented gas.

### 5.3.3.2 LNG Distribution

LNG is generally stored in a saturated liquid state that is described by the Mollier diagram in Figure 5-18. LNG is typically stored at a temperature that is in equilibrium with its temperature. LNG stored at lower pressures is colder than LNG stored at higher pressures. When LNG is stored at pressures above atmospheric, its temperature increases and density decreases.

LNG is stored and distributed in insulated and pressurized storage tanks. In bulk storage tanks that are as large as 500,000 gallons, the storage pressure is 1 psig or lower. Vaporized LNG vents or is drawn off and therefore, the storage pressure does not build up. LNG delivery trucks and local distribution tanks have a capacity of approximately 20,000 gallons and contain LNG at about 50 psig. LNG storage pressures in vehicles depend on the fuel system design and can vary from atmospheric to about 100 psig. At 100 psig fuel pressure, the fuel temperature is about -222°F and the volumetric energy content decreases by about 8 percent compared with LNG that is stored at atmospheric pressure. In order to avoid confusion on the mass of LNG, fuel-cycle emissions are



**Figure 5-18. The phase diagram for LNG shows how the storage temperature increases as storage pressure increases**

calculated for a gallon of LNG at -260°F (atmospheric conditions), although the fuel will be stored at different states.

The analysis for LNG distribution is based on the following emission estimates. LNG is stored in a bulk storage tank. The tank vents periodically and it is assumed that these emissions are sent to a flare. For foreign LNG transported by ship, it is assumed that the ullage space is equilibrated to atmospheric pressure for safety reasons. It is assumed that this gas is burned in a shipboard engine. Energy input requirements for LNG production are adjusted for venting losses.

LNG tank trucks are filled at the LNG terminal in the U.S. Since the tank truck can store LNG at 60 psi pressure, and low pressure LNG is added to the truck, all of the ullage space vapors on the truck can be absorbed into the cold LNG. This might result in a final pressure on the truck of 10 psi. Such vapor management could be readily implemented but is not in place at this time. For current tank truck fillings, it is expected that one half of the ullage space vapors will be vented. For year 2010 scenarios, all of the ullage space vapors will be recondensed into the LNG and hose disconnection losses will be the only vehicle fueling emissions. LNG trucks will not vent enroute to the fueling station during local delivery.

LNG is pressure transferred from the truck to the fueling station. Currently, the pressure for transfer operations is generated by passing LNG through a heat exchanger on the truck. The LNG is pressure transferred to the local storage tank. The ullage space vapors in the storage tank can be reabsorbed into cold fuel from the truck. For top fill storage tanks, the cold liquid can spray into the tank and condense (or collapse) the ullage space. Other techniques for managing the storage tank and tank truck vapor are also possible. Currently, the storage tank ullage and tank truck ullage are vented to some extent depending on the type of fill system. For the years 2000 and 2010, it is expected both tank truck and storage tank vapors will be absorbed into the LNG.

Vehicle fuel tanks are filled according to their design storage pressure. Since cold LNG will expand as it warms in a pressurized tank, these tanks accommodate slightly less fuel. For a vehicle fuel tank with a storage pressure of 40 psi, the vehicle fuel tank is filled to 82 percent full level. The ullage space allows room for expansion as the fuel heats up. As in the case of storage tank transfers, appropriate vapor management can accommodate all of the vapors from the vehicle fuel tank with only minimal hose/fitting venting. Such designs should be in place by the year 2000. Table 5-46 shows the emissions from tank truck transfers for liquefied gases.

Several sources of fuel leaks exist for LNG fueling. The fuel hose and possibly a vapor return hose is connected to the vehicle. Returning vapors to the storage tank offers the best option for heat management. The liquid fuel line and vapor return line are connected to the vehicle. These fuel lines contain vaporized LNG at the storage tank pressure, assumed to be 100 psi for the vehicle tank. When the fuel lines are connected, a small amount of gas escapes as the fittings are coupled together. Acurex Environmental determined the vapor release from LNG fittings by opening a fitting, pressurized with 100 psi gas, and capturing the gas underwater. The trapped vapor was recalculated as LNG vapor escaping from the fitting at sonic conditions. The LNG vapor loss was determined to be 13 mg per connection or 0.052 g for connect and disconnect of two line. Leaks can also occur from the fitting while it is connected. These leaks appear to be minimal over the time required for vehicle fueling.

**Table 5-46. Fuel from gaseous fuel delivery**

Emission Source	Tank Volume (gal)	Liquid Spill Volume		Spill Rate (g/gal)
		(mL/fill)	(mL/gal)	
LPG truck fill outage <sup>a</sup>	—	—	—	2
LPG truck fill hose	10,000	1391	0.139	0.070
LPG local tank hose	10,000	17.4	0.0017	0.0008
LPG local tank outage	—	—	—	5
LNG truck fill hose	11,000	1391	0.6	0.048
LNG tank hose	11,000	20	0.00	0.0007
LNG truck venting <sup>a</sup>	11,000	—	—	5.75

<sup>a</sup>Better vapor management should eliminate this emissions source by the year 2010.

Several LNG fittings were inspected in order to determine trapped fuel volumes which ranged from 4 to 5 mL. Communications with another manufacturer indicated a trapped volume of 2.44 mL. Some fueling facility specifications have required a maximum leakage of 1 mL; however, it is unclear whether this specification has ever been enforced. This study assumes a liquid spill volume of 3 mL.

### 5.3.3.3 LPG Distribution

LPG is stored and distributed in pressurized tanks. The fuel is stored in a liquid state at ambient temperature and the pressure in the tank is in equilibrium. At 70°F the storage pressure is 105 psig. When LPG is transferred from a storage tank to a tank truck, or to a vehicle fuel tank, a transfer pump provides about 50 psi of differential pressure. When fueling vehicle tanks, the fuel enters the tank and the LPG ullage condenses. This process can be accelerated with top loaded tanks where the liquid spray can absorb some of the heat from condensing the vapors.

The tank trucks are filled at refineries with a two hose system with one hose acting as a vapor return. Hoses are evacuated after fuel transfer operations at the refinery. Tank trucks can be filled to a safe fraction of its water capacity by weighing the truck during fueling (Lowi, 1994), although this is not the current practice. However, current regulations require the use of an "outage" valve that indicates when the tank is full. Some LPG also enters the atmosphere from the fuel transfer fitting.

Table 5-46 shows the emissions associated with LPG storage and distribution. The LPG emissions correspond to the volume of liquid that escapes from the fuel transfer fitting divided by the amount of fuel transferred. Currently, LPG vehicles in California are equipped with an "outage" valve that indicates the 80-percent fill level by spilling LPG to the atmosphere. During vehicle fueling, the outage valve is opened and vapors pass through a 0.060-inch orifice and through the valve. When LPG reaches the 80 percent level in the vehicle tank, liquid enters the fill level line and exits into the atmosphere. A puff of white liquid is visible to the fueler, which provides an additional signal that the tank is full. California's vehicle code requires use of the outage valve. As indicated in Table 5-43, emissions from vehicle fueling are several grams per gallon.

Many LPG tanks are already equipped with automatic stop-fill devices that could eliminate fuel tank vapor venting; however, Titles 8 and 13 of the California Administrative Code require the use of the outage valve. Other countries, including the Netherlands where many LPG vehicles operate, do not use the outage valve for fueling. One might expect that many LPG vehicles in California are fueled without using the outage valve if they are equipped with automatic stop fill devices.

A committee of NFPA, CHP, NPGA, and WLPGA representatives are working to set standards that will allow LPG vehicles to be fueled without leaking LPG to the atmosphere. Equipment that will minimize the fuel released from transfer fittings is also being approved (Wheeler, 1994). EPA regulations on evaporative emissions from vehicles will also eliminate outage valve emissions.

Emission estimates for LPG fueling are based on the following conditions:

- 1391-cc loss from fuel couplings on 10,000-gallon delivery trucks. Fluid loss is equivalent to 18 inches of 1.25-inch-diameter (inner diameter) hose (Lowi, 1992)
- Current vehicle hose coupling liquid losses are 7.57 cc (Lowi, 1992) for a 12-gallon fuel transfer. Dry-break couplings would have less than 5 percent of the trapped volume of current LPG nozzles of the same capacity. The use of these nozzles is expected beyond the year 2000.
- Current fuel tank vapor displacement is based on sonic flow through a 1.5-mm orifice, 70°F tank temperature with a fuel pressure of 105 psig. Assuming an orifice discharge coefficient of 0.5 results in 2 g/s of vapor flow. With an 8 gal/min flow rate, vapor displacement is 15 g/gal.
- Vapor displacement from current tank truck filling assumes a 100 gal/min fill rate with an outage loss of 2 g/s.

#### **5.3.3.4 LH<sub>2</sub> Storage and Distribution**

Emissions from hydrogen storage and distribution are not counted in any of the emission categories in this study. These losses are however counted towards the total hydrogen required to produce a delivered lb of hydrogen. The principal hydrogen losses occur during bulk storage and local storage venting. Since hydrogen has such a low boiling point compared with LNG, heat transfer rates is greater and venting is more likely to occur. Some of the hydrogen may be recovered at the bulk facility; however, reliquefaction or burning it as a fuel will result in a net increase in energy input. This study assumes a 1 percent loss of hydrogen for LH<sub>2</sub> applications in Scenarios 2, 3, and 4.

#### **5.3.4 Electricity Distribution**

Electricity distribution results in losses through the power lines. Typical transmission losses range from 3.5 to 13.5 percent. This value depends on the specific application. Transmission losses are built into the power generation requirements discussed in Section 5.2.6. CEC's ELFIN runs took into account the average distribution losses for LADWP and SCE (around 9 and 7 percent respectively). This simplification probably overstates emissions in the South Coast Air Basin for

several reasons. First, the distance required for power distribution and associated distribution losses are smaller for power generated in the South Coast Air Basin than for the utility company average. Therefore, the energy inputs for power produced in the South Coast Air Basin are probably overstated. Secondly, the ELFIN runs predict a South Coast Air Basin power generation mix between 49 and 58 percent for incremental (RECLAIM constrained) power compared with 21.7 percent for average power (note the %Energy, Total South Coast Air Basin, year 2010, entries in Tables 5-36, 5-37, and 5-38. Even if transmission losses were not adjusted for local production, a higher local mix of local power production should drop the average distribution loss rate. Based on these considerations, the total emissions for South Coast Air Basin power, including transmission are probably overstated by at least 2 percent, while emissions associated with out of basin power are understated.

Losses also occur during vehicle charging. The magnitude of these losses depend on the battery type and charging system. EV energy consumption is reported in terms kWh of electricity at the outlet; therefore the EV energy consumption includes charging losses. Actual energy consumption could vary with the type of EV charger and the state of battery charge.

## 5.4 EMISSION CALCULATIONS

Emissions per unit of fuel were calculated for the fuel and feedstock combinations in Table 4-1. Emissions are partitioned by their geographic location and production phase. The data base calculation makes the partitioning simpler. The data base approach also allows for better tracking of ozone potential factors and modifying the results if new data are available. Emission rates in Section 5 are included in the EFACTOR data base in Appendix B (Figure 5-19). The first columns indicate the feedstock or fuel code. Lower case codes represent feedstocks and upper case codes represent product fuels. Values from Section 5 are located in the next group of columns without a change in the units. The code for the NMOG source follows the NMOG emissions. This code relates to the specific reactivity values in the SPROF data base. Btus following the reactivity code are represented in the same units as emissions (e.g. Btu/bhp-hr and g/bhp-hr). The next group of columns includes factors to convert from input values to a final calculation of emissions. The simplest values are fugitive emissions, for example, g/100 scf of natural gas. No conversion factor is used and the right group of columns also shows CH<sub>4</sub> and NMOG in g/100 scf. Btus are calculated from the fuels higher heating value and are used to track total energy use in the fuel cycle. CO<sub>2</sub> is calculated assuming that hydrocarbons react to produce CO<sub>2</sub> in the atmosphere for the factors from Table 2-1.

In order to readily use the same emission rates for a range of use factors, some of the emissions are in mixed units which are taken into account in the next data base calculation. For natural gas pipeline distribution, the conversion factors are 0.9 hp-hr/MMscf/mi, a baseline usage factor of 1000 mi, an 10<sup>-4</sup> (100 scf)/MMscf. These factors convert the emissions into g/100 scf for 1000 miles traveled. Emissions sources with mixed units include the following:

- Natural gas engine emissions      g/100 scf/1000 mi
- Tanker ship emissions      g/gal(fuel or crude)/1000 nautical mi
- Electricity use      g/kWh (primary unit for EVs but mixed for fuel production)
- Boiler emissions      g/10,000 Btu
- Farm equipment emissions      g/10,000 Btu
- Rail car emissions      g/gal fuel/1000 mi

			FC	EMI	NOX	CO	CH4	NMOG	CO2	Btu	lb CO2/M	Notes
mi	9.00E-02	100scf/MMscf/hp-hr	n	51.1	0.18	0.2385	0.3978	0.0405	41.67	720		per 1000 miles pipeline/100s
mi	1.00E-04	100scf/MMscf	n	51.2	0.0396	0.27	0.45	0.045	41.67	720		per 1000 miles pipeline/100s
mi	1.00E-04	100scf/MMscf	n	51.3	0.54	0.2385	0.3978	0.0405	41.67	720		per 1000 miles pipeline/100s
mi	1.00E-04	100scf/MMscf	n	51.4	0.18	0.27	0.45	0.045	41.67	720		per 1000 miles pipeline/100s
mi	1.00E-04	100scf/MMscf	n	52.1	0.036	0.0747	0.0153	0.0009	53.91	990		per 1000 miles pipeline/100s
mi	1.00E-04	100scf/MMscf	n	52.2	0.0153	0.09	0.018	0.0009	53.91	990		per 1000 miles pipeline/100s
mi	1.00E-04	100scf/MMscf	n	52.3	0.153	0.0747	0.0153	0.0009	53.91	990		per 1000 miles pipeline/100s
mi	1.00E-04	100scf/MMscf	n	52.4	0.09	0.09	0.018	0.0009	53.91	990		per 1000 miles pipeline/100s

FC	EMI DESCRIPTION	NOX	CO	CH4	NMOG	PROFILE	CO2	Btu	UNITS	Conversion Factors c = (a/f)*b
n	51.1 NG Recip SC - 1993	2.0	2.65	4.42	0.45	1001	463	8000	g/bhp-hr	0.9 hp-h/MMscf/mi
n	51.2 NG Recip SC - 2010	0.4	3.00	5.00	0.5	1001	463	8000	g/bhp-hr	0.9 hp-h/MMscf/mi
n	51.3 NG Recip CA - 1993	6.0	2.65	4.42	0.45	1001	463	8000	g/bhp-hr	0.9 hp-h/MMscf/mi
n	51.4 NG Recip CA - 2010	2.0	3.00	5.00	0.5	1001	463	8000	g/bhp-hr	0.9 hp-h/MMscf/mi
n	52.1 NG GT SC - 1993	0.4	0.83	0.17	0.01	3	599	11000	g/bhp-hr	0.9 hp-h/MMscf/mi
n	52.2 NG GT SC - 2010	0.17	1.0	0.2	0.01	3	599	11000	g/bhp-hr	0.9 hp-h/MMscf/mi
n	52.3 NG GT CA - 1993	1.7	0.83	0.17	0.01	3	599	11000	g/bhp-hr	0.9 hp-h/MMscf/mi
n	52.4 NG GT CA - 2010	1.0	1.0	0.2	0.01	3	599	11000	g/bhp-hr	0.9 hp-h/MMscf/mi
n	53.1 Transmission	0	0	7.8897	0.7803	9993		429.7	g/100scf	49.6 Btu/g

Figure 5-19. Emission rates in the EFACTOR database

- Refinery emissions g/gal gasoline
- Tank truck emissions g/gal/50 mi

Other emission rates are simply stated per unit of end product. These include the following:

- Fuel transfer emissions g/gal
- Natural gas fugitive emissions g/100 scf
- Methanol production emissions g/gal
- Methanol plant fugitive emissions g/gal
- Ethanol plant fugitive emissions g/gal

The VIEW data base combines the values in EFACTOR with the location of fuel production facilities and transportation routes identified in Section 4 and 5.1. Figure 5-20 shows an example from VIEW. The first column identifies the feedstock/fuel combination with its code and description. The scenario and production phase are identified in the next columns followed by the percentage allocation of emissions by geographic location. One or more emission codes are identified for each production phase. The phase weight is the product of the A, CD, and Use factors. The A factor represents the contribution of the emission source towards the finished fuel production. For example, A=88 for M100 shipments for M85 production (88-percent methanol). The CD factor takes into account emission controls as well as distance traveled. The Use factor takes into account usage factors such as gallons of methanol for MTBE per gallon of gasoline or kWh of power used per unit fuel produced. The accounting of pipeline transmission emissions is more complicated. Separate emission rates are used for gas turbines and reciprocating engines. The EFACTOR data base shows emissions on a g/100 scf/1000 miles basis. These emissions are further broken down by South Coast Air Basin engines and others. The 50 percent A factor represents the split between gas turbines and reciprocating engines. Since emission controls do not affect pollutants uniformly, a separate emission rate is used for each emission control assumption. The geographic allocation for the South Coast is 5 percent or 50 mi. The total percentage allocation adds to greater than 100 percent in proportion to the total mileage for transmission (1350).

For Scenario 2, Phase *ph*, in the South Coast Air Basin, emissions are calculated according to the routine outlined below.

$$E_{2/ph,SC} = \sum ([EM1 + EM2 + EM3 + EM4] \times SC \times pHWt)_{ph=2} \quad (5-8)$$

MIR ozone potential is calculated from the following:

$$OPMIR_{2,ph,SC} = \sum \left( \sum [EM_j \times MIR_j \times SC \times PhWt]_{ph=2} \right) \quad (5-9)$$

For example, for transmissions, Phase 5, MIR ozone potential in the South Coast Air Basin is calculated as:

CC	Fuel	ScPh	SC	CA	US	ROW	EM1	EM2	EM3	EM4	FC	PHwt	A	CD	Use
nC	CNG	1 1 Production	20	0	60	20	11.2				n	1,000	1.00	1.00	1.00
nC	CNG	1 2 Incl in production	20	0	60	20	23.1				n	0,000	1.00	0.00	1.00
nC	CNG	1 3 Sweetner plant	5	25	64	6	31.1				n	1,000	1.00	1.00	1.00
nC	CNG	1 4 Pipeline	20	0	60	20	41.1				n	1,000	1.00	1.00	1.00
nC	CNG	1 5 G.T.s CA/ROW 1990	0	25	66	6	52.3				n	0,450	0.45	1.00	1.00
nC	CNG	1 5 G.T.s SC 1990	5	0	0	0	52.1				n	0,450	0.45	1.00	1.00
nC	CNG	1 5 Recips CA/ROW 1990	0	25	66	6	51.3				n	0,550	0.55	1.00	1.00
nC	CNG	1 5 Recips SC 1990	5	0	0	0	51.1				n	0,550	0.55	1.00	1.00
nC	CNG	1 5 Transmission	5	25	64	6	53.1				n	1,000	1.00	1.00	1.00
nC	CNG	1 6 Storage	100	0	0	0	61.1				n	1,000	1.00	1.00	1.00
nC	CNG	1 7 Compress, SC 1990	100	0	0	0	79.1				xJ	1,200	1.00	1.20	1.00
nC	CNG	1 7 Compress CA/US 90	0	25	57	0	79.2				xJ	1,200	1.00	1.20	1.00
nC	CNG	1 7 Distrib. leaks	100	0	0	0	73.1				C	1,000	1.00	1.00	1.00
nC	CNG	1 8 Fill leaks	100	0	0	0	82.1	82.4			C	1,000	1.00	1.00	1.00
nC	CNG	2 1 Production	0	0	50	50	11.2				n	1,000	1.00	1.00	1.00
nC	CNG	2 2 Incl in production	0	0	50	50	23.1				n	1,000	1.00	1.00	1.00
nC	CNG	2 3 Sweetner plant	0	0	50	50	31.1				n	1,000	1.00	1.00	1.00
nC	CNG	2 4 Pipeline	0	0	50	50	41.1				n	1,000	1.00	1.00	1.00
nC	CNG	2 5 G.T.s CA/ROW 2010	0	23	97	10	52.4				n	0,500	0.50	1.00	1.00
nC	CNG	2 5 G.T.s SC 2010	5	0	0	0	52.2				n	0,500	0.50	1.00	1.00
nC	CNG	2 5 Recips CA/ROW 2010	0	23	97	10	51.4				n	0,500	0.50	1.00	1.00
nC	CNG	2 5 Recips SC 2010	5	0	0	0	51.2				n	0,500	0.50	1.00	1.00
nC	CNG	2 5 Transmission	4	17	72	7	53.1				n	1,000	1.00	1.00	1.00
nC	CNG	2 6 Storage	100	0	0	0	61.1				n	1,000	1.00	1.00	1.00
nC	CNG	2 7 Compress SC 2010	100	0	0	0	79.3				xJ	1,200	1.00	1.20	1.00
nC	CNG	2 7 Compress CA/US 2010	0	23	55	0	79.4				xJ	1,200	1.00	1.20	1.00
nC	CNG	2 7 Distrib. leaks	100	0	0	0	73.1				C	1,000	1.00	1.00	1.00
nC	CNG	2 8 Fill leaks	100	0	0	0	82.1	82.4			C	0,800	1.00	0.80	1.00

Figure 5-20. Emission allocation in VIEW database

$$\begin{aligned}
 & \text{EM} \quad \text{MIR} \quad \text{SC} \quad \text{pHWt} \\
 \text{OPMIR}_{2,5,SC} &= (0.50 \times 0.41 \text{MIR} \times 0.05 \times 0.5) \text{ Reciprocating engines (n51.2)} \\
 &+ (0.01 \times 0.41 \text{MIR} \times 0.05 \times 0.5) \text{ Gas turbines (n52.2)} \\
 &+ (0.78 \times 0.03 \text{MIR} \times 0.04 \times 1.0) \text{ Transmission losses (n53.1)} \\
 &= 0.018 \text{ gO}_3/100\text{scf} \qquad \qquad \text{Total}
 \end{aligned} \tag{5-10}$$

Another example is gasoline distribution, Scenario 3, Phase 8, NMOG in the South Coast Air Basin which is calculated as follows:

$$\begin{aligned}
 & \text{EM1} \quad \text{EM2} \quad \text{SC} \quad \text{pHWt} \\
 \text{NMOG}_{3,8,SC} &= ([0.2086 + 0.4123] \times 1 \times 1) \text{ Distribution fugitives (G82.2,G82.3)} \\
 &+ ([0.3175 + 0] \times 1 \times 0.6) \text{ Distribution spills (G82.4)} \\
 &= 0.811 \text{ gNMOG/gal} \qquad \qquad \text{Total}
 \end{aligned} \tag{5-11}$$

The EFACTOR data base includes a profile field which identifies the specific reactivity for NMOG emissions which are in the SPROF2 data base. Fuel-cycle emissions are calculated on a g/unit fuel and presented in the RSLTSGPG data base. These results are sorted by fuel/feedstock combination. The RSLTSGPG data base is related with fuel consumption in the FELOW data base to calculate emissions on a g/mi basis.

## 5.5 MARGINAL EMISSION ANALYSIS

Emissions for incremental alternative fuel production and gasoline displacement were calculated for fuel cycle activities in the South Coast Air Basin. The average emission values were adjusted according to Table 5-47. The net result of the incremental analysis is that NO<sub>x</sub> emissions amount only to tanker ship and truck emissions in the South Coast Air Basin. All other NO<sub>x</sub> emissions are either controlled by RECLAIM or are associated with fuel production out side of the South Coast Air Basin. NMOG emissions correspond to fuel storage and distribution activities as well as power production for EVs.

**Table 5-47. Adjustments for marginal fuel cycle emission analysis in the South Coast Air Basin, 2010**

<b>Fuel</b>	<b>Marginal analysis assumption</b>
Gasoline, RFG, diesel, LPG	Zero emissions for Phases 1 through 3. Add emissions for tanker ship imports of finished fuel.
Methanol and ethanol	Produced outside of the South Coast, so there is no change in emissions. Zero emissions for Phases 1 through 3 (emissions associated with RFG production)
CNG	Zero emissions for Phases 1 through 7 except for pipeline transmission emissions in Phase 5. Emissions associated with pipeline leakage do not increase with increased throughput.
EV	Zero emissions for Phases 1 and 2 (second order feedstock production and transmission emissions) Include emissions for Phase 3. NO <sub>x</sub> would be zero for electric power generation associated with liquefaction (no South Coast Air Basin generation was assumed in this study)
LNG, LH <sub>2</sub>	Produced outside of the South Coast, so there is no change in emissions.

## SECTION 6

### COMPARISON OF EMISSIONS

#### 6.1 FUEL-CYCLE EMISSIONS PER UNIT FUEL

The total fuel-cycle emissions were calculated using the emission rates in Section 5 and the Scenario assumptions in Section 4. The emissions were categorized by fuel/feedstock combination, scenario, geographic distribution of emissions, and fuel-cycle phase. The combination of variables represent over 20,000 emission calculations which were performed by a relational data base. The fuel-cycle emissions are shown for each unit of fuel in Appendix B. Comparisons of the emissions from different production processes are discussed below.

The tables in Appendix B show the emissions grouped by geographic source. This presentation is not particularly interesting for comparative purposes, but represents a close tie to the data in Sections 4 and 5.

Observations from these results include the following:

- NMOG emissions are highest from the fuel distribution phases
- Fugitive emissions from methanol, ethanol, LNG, and LPG are much higher in 1992 than in future years. Higher throughput for alcohols will decrease the per gallon emissions from fuel storage tanks. Emissions from LNG and LPG are assumed to improve as provisions are made for fuel transfer without vapor releases.

#### 6.2 VEHICLE FUEL CONSUMPTION

Table 6-1 shows the fuel economy values for vehicles in this study. The energy efficiency ratio represents the energy consumption of conventional gasoline-fueled vehicles divided by the energy consumption of alternative-fueled vehicles (lower heating value basis). A vehicle with an energy efficiency ratio of 1.05 is 5 percent more efficient than a gasoline-fueled vehicle or uses 5 percent less Btu per mile.

Energy efficiency is based on the assessment of vehicle fuel economy data as well as projections of the potential for alternative-fueled vehicles. Diesel cars are in production and have a history of improved fuel economy. Some data are available on production methanol FFVs. Production versions of all of the other alternative-fueled vehicles were not produced by major manufacturers in California in 1992. Since the emissions and fuel economy performance of older retrofit CNG and LPG engines were not equivalent to that of gasoline, these fuels were assigned a lower fuel efficiency for Scenario 1. LPG and CNG vehicles may offer some efficiency improvements over gasoline; however, such improvements are intertwined with differences in vehicle

**Table 6-1. Fuel economy assumptions for light-duty vehicles**

<b>Fuel (unit)</b>	<b>Scenario</b>	<b>LHV (Btu/unit)</b>	<b>Energy Efficiency Ratio</b>	<b>Fuel Economy (mi/unit)</b>	<b>Fuel Use Ratio</b>	<b>Exhaust CO2 Emissions (g/mi)</b>	<b>Carbon as CO2 (lb/unit)</b>
Gasoline (gal)	1	115,400	1.00	23.00	1.00	366.5	18.6
RFG (gal)	1	113,000	1.00	22.52	1.02	366.4	18.2
Diesel (gal)	1	130,800	1.20	31.28	0.74	322.3	22.2
LPG (gal)	1	83,000	1.00	16.54	1.39	345.8	12.6
M85 NG (gal)	1	64,390	1.05	13.48	1.71	348.6	10.3
M85 biomass (gal)	1	64,390	1.05	13.48	1.71	46.3	1.4
M100 (gal)	1	57,000	1.05	11.93	1.93	347.7	9.1
E85 (gal)	1	81,870	1.05	17.13	1.34	59.9	2.3
CNG (100 scf)	1	92,800	1.00	18.50	1.24	303.4	12.4
LNG (gal)	1	72,900	1.00	14.53	1.58	295.8	9.5
H2(lb)	1	51,600	1.05	10.80	2.13	0.0	0.0
Electric (kWh)	1	3,412	4.20	2.86	8.05	0.0	0.0
Gasoline (gal)	2,3	115,400	1.00	27.50	1.00	306.5	18.6
RFG (gal)	2,3	113,000	1.00	26.93	1.02	306.5	18.2
Diesel (gal)	2,3	130,800	1.20	37.40	0.74	269.6	22.2
LPG (gal)	2,3	83,000	1.03	20.37	1.35	280.8	12.6
M85 NG (gal)	2,3	64,390	1.03	15.80	1.74	297.2	10.3
M85 biomass (gal)	2,3	64,390	1.03	15.80	1.74	39.5	1.4
M100 (gal)	2,3	57,000	1.05	14.26	1.93	290.8	9.1
E85 (gal)	2,3	81,870	1.03	20.10	1.37	51.0	2.3
CNG (100 scf)	2,3	92,800	1.03	22.78	1.21	246.4	12.4
LNG (gal)	2,3	72,900	1.03	17.89	1.54	240.2	9.5
LH2(lb)	2,3	51,600	2.00	24.59	1.12	0.0	0.0
Electric (kWh)	2,3	3,412	4.92	4.00	6.88	0.0	0.0
Gasoline (gal)	4	115,400	1.00	32.00	1.00	263.4	18.6
RFG (gal)	4	113,000	1.00	31.33	1.02	263.4	18
Diesel (gal)	4	130,800	1.20	43.52	0.74	231.7	22
LPG (gal)	4	83,000	1.05	24.17	1.32	236.7	13
M85 NG (gal)	4	64,390	1.05	18.75	1.71	250.5	10.3
M85 biomass (gal)	4	64,390	1.05	18.75	1.71	33.3	1.4
M100 (gal)	4	57,000	1.10	17.39	1.84	238.6	9
E85 (gal)	4	81,870	1.05	23.84	1.34	43.0	2
CNG (100 scf)	4	92,800	1.05	27.02	1.18	207.7	12
LNG (gal)	4	72,900	1.05	21.23	1.51	202.5	9
LH2(lb)	4	51,600	2.00	28.62	1.12	0.0	0
Electric (kWh)	4	3,412	5.28	5.00	6.40	0.0	0

Fuelnorm.xls

acceleration and weight. Therefore, the LPG, CNG, LNG, and M100 vehicles represent a hypothetical vehicle. The basis for the hydrogen vehicle in Scenarios 2, 3, and 4 is a fuel cell powered electric vehicle which has the potential for high energy efficiency because of the high energy conversion efficiency of fuel cells. Electric vehicles are also very efficient because thermal conversion has already been performed at the power plant.

The fuel economy comparison is conceptually difficult since equivalent vehicles will not be available in all size categories for all of the alternative fuels. Alternative fuels will more likely be sold in markets where the fuel makes the most sense. Electric vehicles may be smaller than the baseline gasoline vehicle. They may also not have the same cargo hauling capability or exactly the same performance. However, the electric vehicle might well displace a gasoline vehicle with greater range or carrying capacity. Likewise, a CNG vehicle might lack the same cargo capacity as a gasoline car. All of the alternatives will have different attributes and characteristics compared to the baseline gasoline. Therefore, Table 6-1 should be considered as a normalized assessment of equivalent fuel economy.

The fuel use ratio indicates the amount of fuel needed to displace one gallon of conventional gasoline. Since reformulated gasoline contains MTBE, 2 percent more fuel is required for vehicles with the same efficiency as conventional gasoline vehicles. Fuel economy for 1992 gasoline vehicles represents an estimate of the on-road fleet. Again, by assuming vehicles with an equivalent fuel economy, second order effects on the gasoline vehicle fleet mix are implicitly inconsequential. However, the use of alternative fuels will undoubtedly affect the gasoline vehicle mix since these vehicles will not be uniformly distributed across the vehicle line. For example, CNG vehicles could find more extensive use in larger vehicles such as light trucks. If for example, CNG vehicles replaced larger vehicles, then their fuel cycle emissions would be larger than those indicated by this study. Therefore, fuel economy for alternative fueled vehicles are based on a baseline gasoline fuel economy. A baseline fuel economy of 27.5 mpg for gasoline cars is used for Scenarios 2 and 3. A higher fuel economy case for Scenario 4 reflects reductions in fuel use that are consistent with the National Energy Strategy. The fuel efficiency of alternative-fueled vehicles was increased for the high fuel economy case. Greater extremes in fuel-cycle emissions could be illustrated by assuming higher alternative-fueled vehicle efficiency with lower gasoline vehicle efficiency.

### **6.3 MILEAGE EQUIVALENT FUEL-CYCLE EMISSIONS**

Fuel-cycle emissions were compared on a g/mi basis for the fuel economy values in Table 6-1 and the fuel and feedstock combinations in Table 6-2. The fuel-cycle emissions are categorized by extraction (Phases 1 and 2), production (Phase 3), marketing (Phases 4, 5, 6, and 7), and distribution (Phase 8). Table 6-3 shows how marginal emissions are determined. Figures 6-1 through 6-44 illustrate the results on a g/mi basis.

Figures 6-1 through 6-8 show average NO<sub>x</sub> emissions for Scenarios 1 through 4 in the South Coast air Basin as well as California and U.S. emissions for Scenario 3, and total global emissions for Scenarios 3 and 4. The global emissions include the emissions in the South Coast, California, the United States, and the rest of the world. The results for Scenario 4 reflect the effect of vehicle fuel economy.

Figures 6-9 through 6-16 show average NMOG emissions for Scenarios 1 through 4 in the South Coast Air Basin as well as California and U.S. emissions for Scenario 3, and total global

**Table 6-2. Fuel-cycle emissions were categorized into eight production and distribution scenarios**

Phase No.	Description
<u>Extraction</u>	
1.	Feedstock extraction
2.	Feedstock transportation
<u>Production</u>	
3.	Fuel processing/refining
<u>Marketing</u>	
4.	Fuel storage at processing site
5.	Transport to bulk storage
6.	Bulk storage
7.	Transport to local distribution station
<u>Distribution</u>	
8.	Local station distribution

**Table 6-3. Procedure for calculating marginal emissions in Scenarios 2, 3, and 4**

Fuel	Case Code	Fuel-Cycle Phases set to Zero for Marginal Analysis	
		NO <sub>x</sub>	NMOG
Gasoline	oG	1, 2, and 3	1, 2, and 3
RFG	oR	1, 2, and 3	1, 2, and 3
Diesel	oD	1, 2, and 3	1, 2, and 3
LPG	oP	1, 2, and 3	1, 2, and 3
M85 from NG	nN	1, 2, and 3	1, 2, and 3
M85 from biomass	bN	1, 2, and 3	1, 2, and 3
M100 from NG	nM	1, 2, and 3	1, 2, and 3
E85	bE	1, 2, and 3	1, 2, and 3
CNG	nC	1, 2, and 3	1, 2, 3, 4, 5, 6, 7
LNG	nL	—	—
Hydrogen	nH	—	—
Electric	xJ	3	1 and 2

emissions for Scenarios 3 and 4. Figures 6-17 through 6-24 show the ozone potential for average fuel production in the South Coast Air Basin on the MIR and MOR scales. Figures 6-25 through 6-28 show average CO emissions in the South Coast Air Basin.

Figures 6-29 through 6-36 show total global CO<sub>2</sub> and CH<sub>4</sub> emissions. Some of the fuel-cycle components include negative values due to by-product credits and electric power generation credits for biomass-derived fuels. Total CO<sub>2</sub> emissions can be determined by adding the exhaust emissions in Table 6-1 to the fuel-cycle emissions. This comparison provides a good illustration of the low CO<sub>2</sub> contributions of EVs and hydrogen-fueled vehicles.

Figures 6-37 through 6-44 show the results of the marginal emission analyses for NO<sub>x</sub>, NMOG, and ozone potential (MIR and MOR). These are shown for Scenarios 2 and 3, which represent assumptions closest to emission factors considered in the SCAQMD emission inventory.

In the year 2000, approximately 1 trillion miles will be driven by automobiles in California. This value should remain fairly constant whether all the miles driven used conventional gasoline or a mixture of alternative fuels. Considerations regarding marginal emissions should be reexamined if the fuel-cycle emissions are used to determine emission inventories for air quality modeling purposes. In particular, the number of storage tanks for local distribution should be matched to assumptions on vehicle fleet populations. Further attention should be given to adjusting stationary source inventories to completely account for all petroleum operations that do not relate directly to incremental alternative fuel vehicle operation. For example, emissions from gasoline pleasure boat refueling should remain in the inventory even if alternative fuels displaces gasoline.

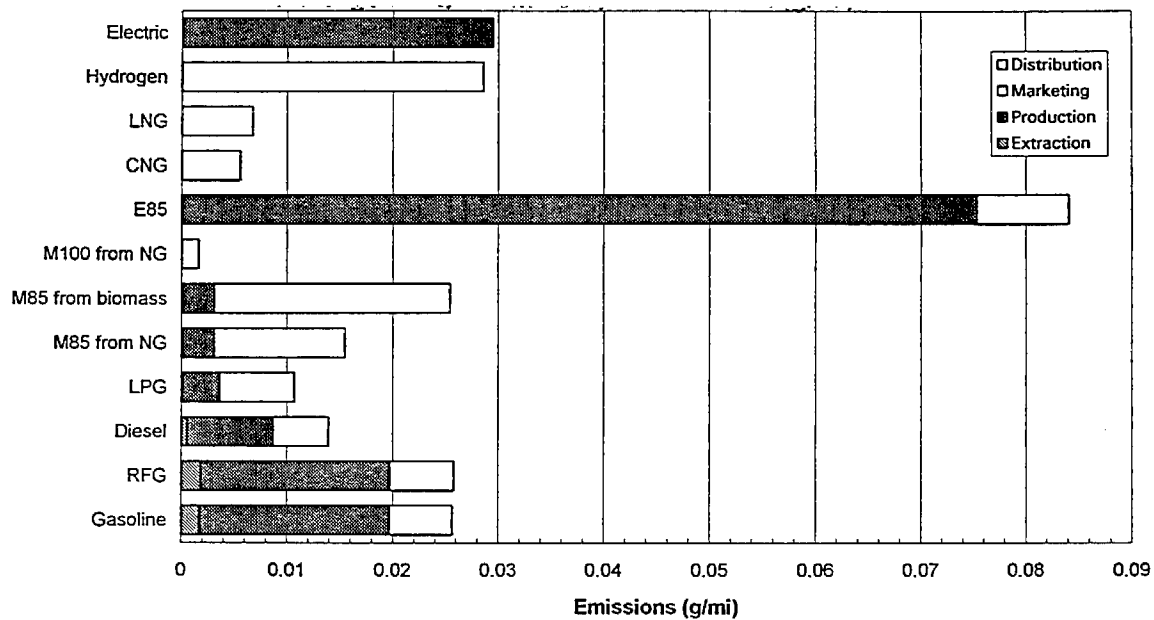


Figure 6-1. Average NO<sub>x</sub>, Scenario 1, South Coast (g/mi)

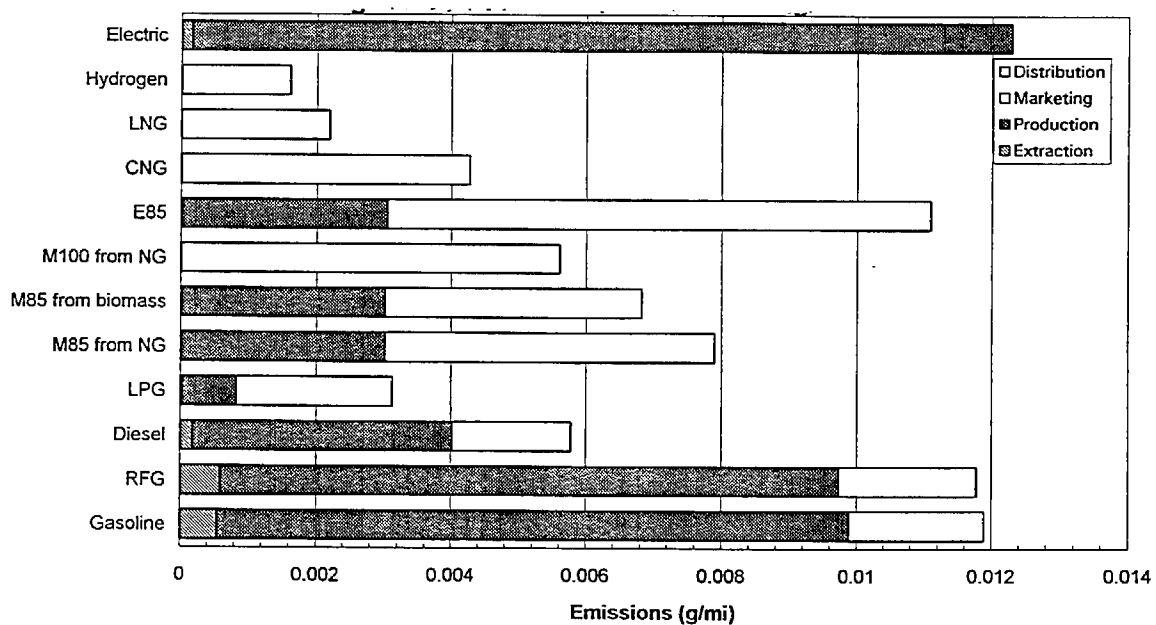


Figure 6-2. Average NO<sub>x</sub>, Scenario 2, South Coast (g/mi)

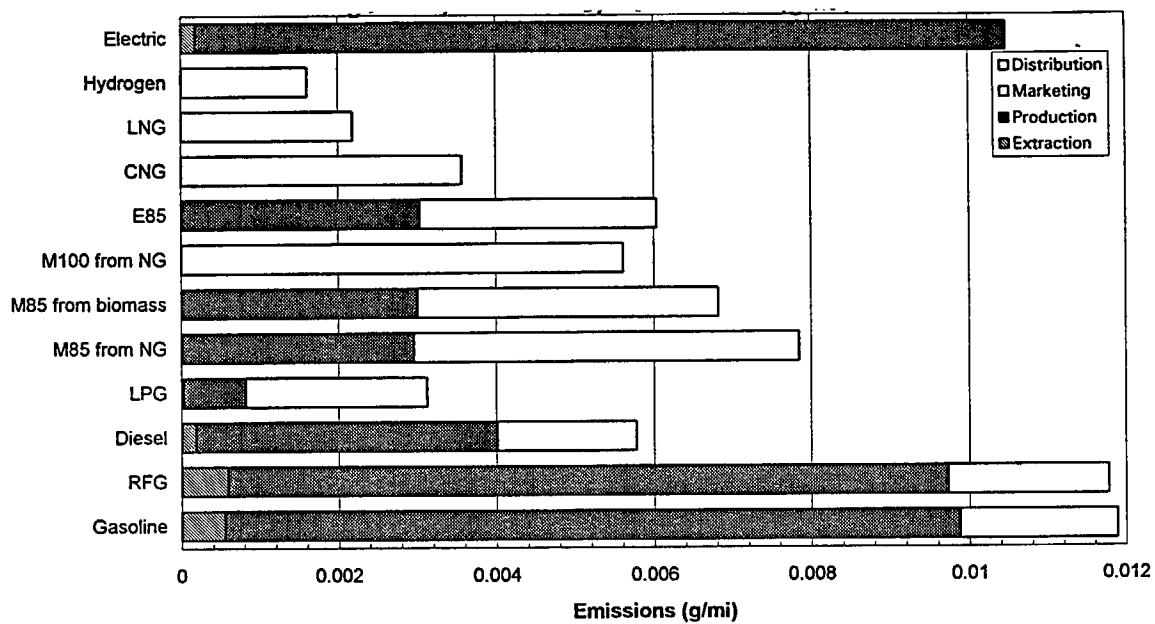


Figure 6-3. Average NO<sub>x</sub>, Scenario 3, South Coast (g/mi)

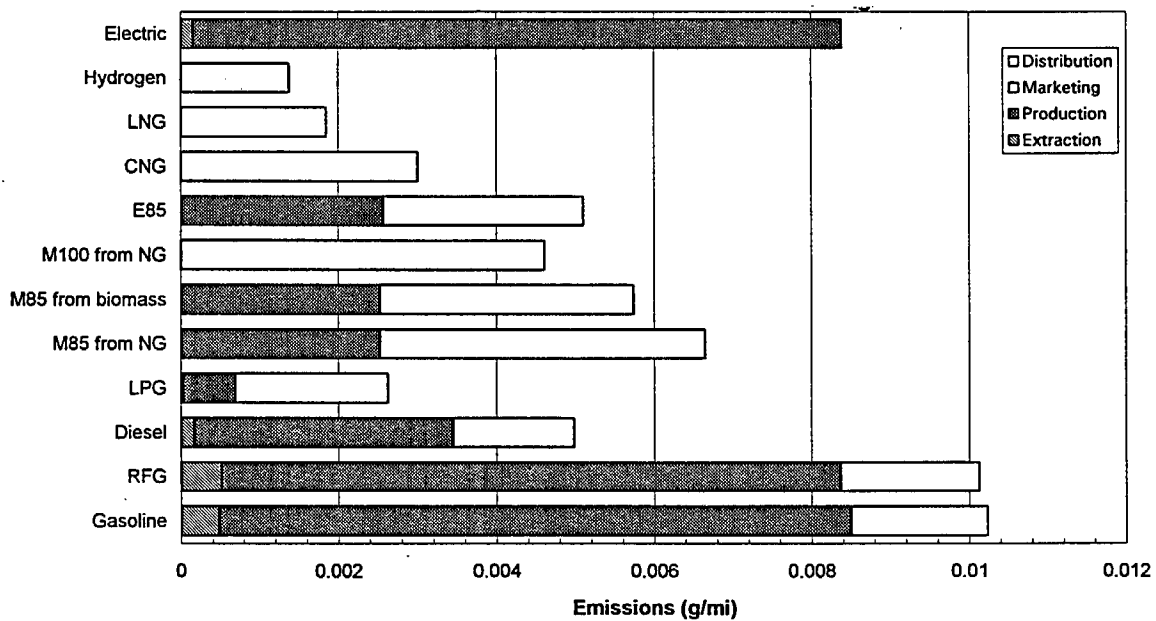


Figure 6-4. Average NO<sub>x</sub>, Scenario 4, South Coast (g/mi)

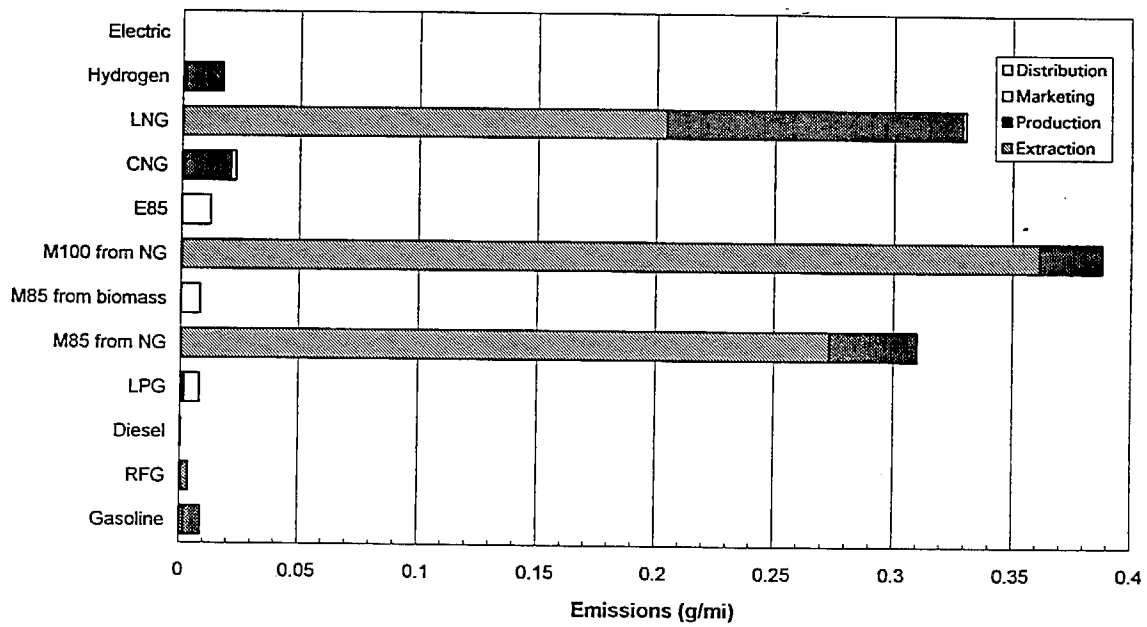


Figure 6-5. Average NO<sub>x</sub>, Scenario 3, California excluding South Coast (g/mi)

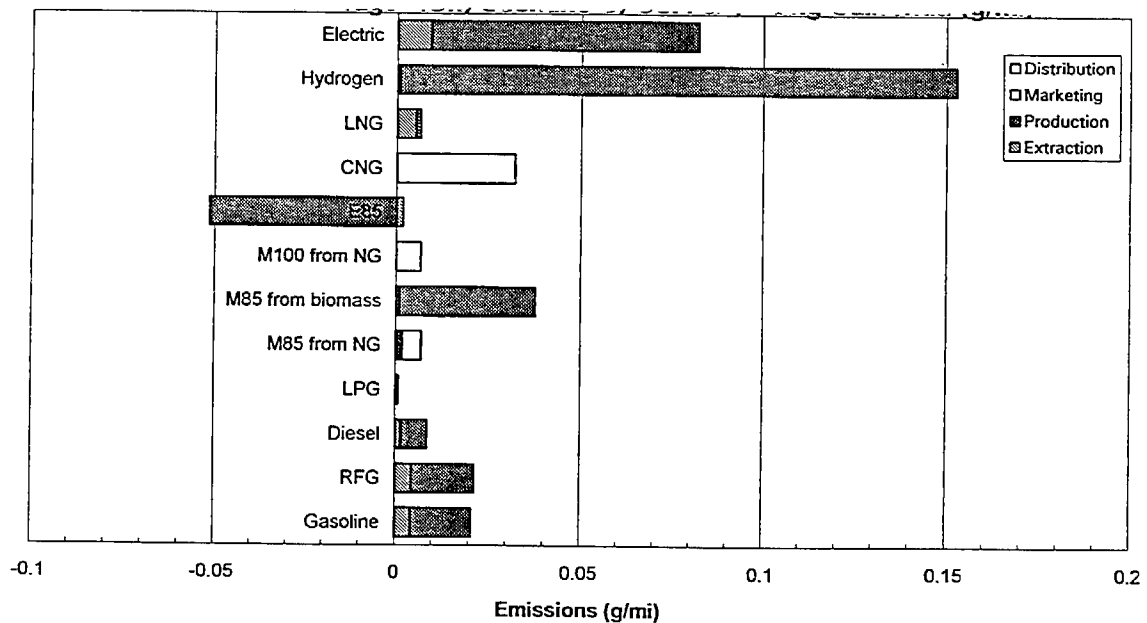


Figure 6-6. Average NO<sub>x</sub>, Scenario 3, USA excluding California (g/mi)

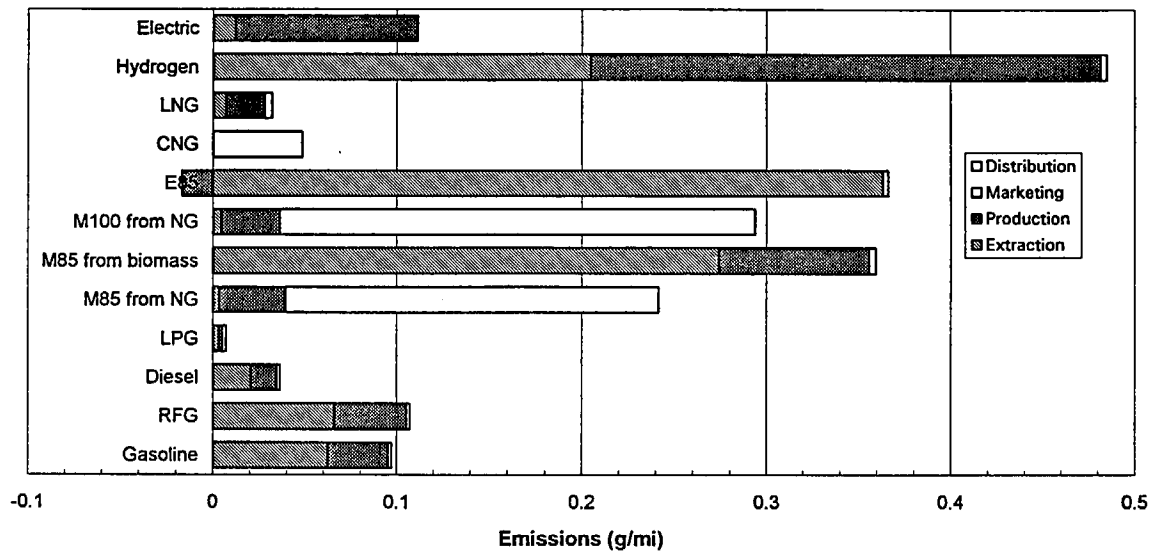


Figure 6-7. Global average NO<sub>x</sub>, Scenario 3 (g/mi)

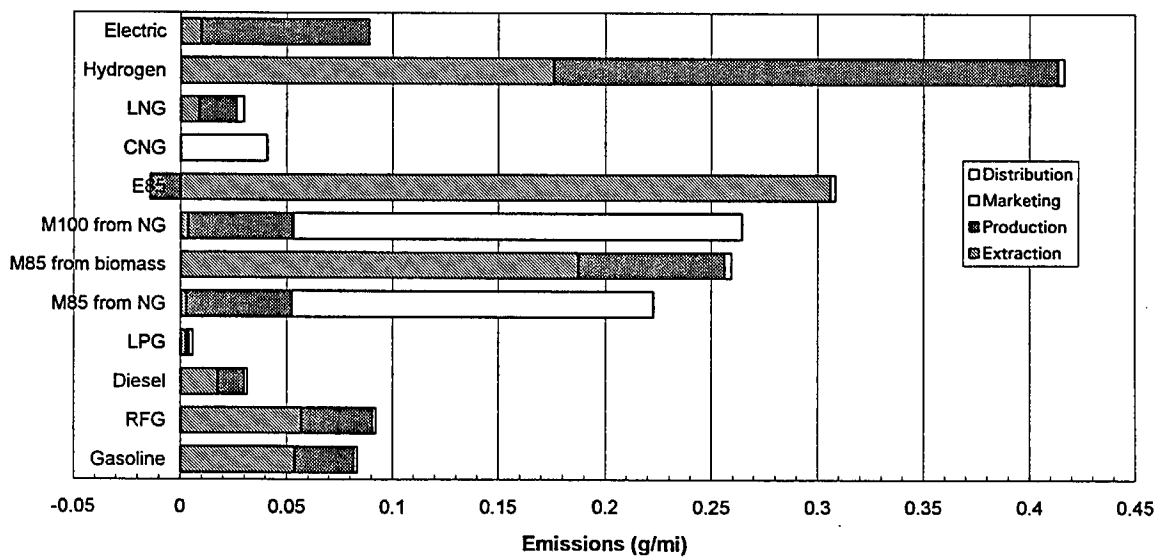


Figure 6-8. Global average NO<sub>x</sub>, Scenario 4 (g/mi)

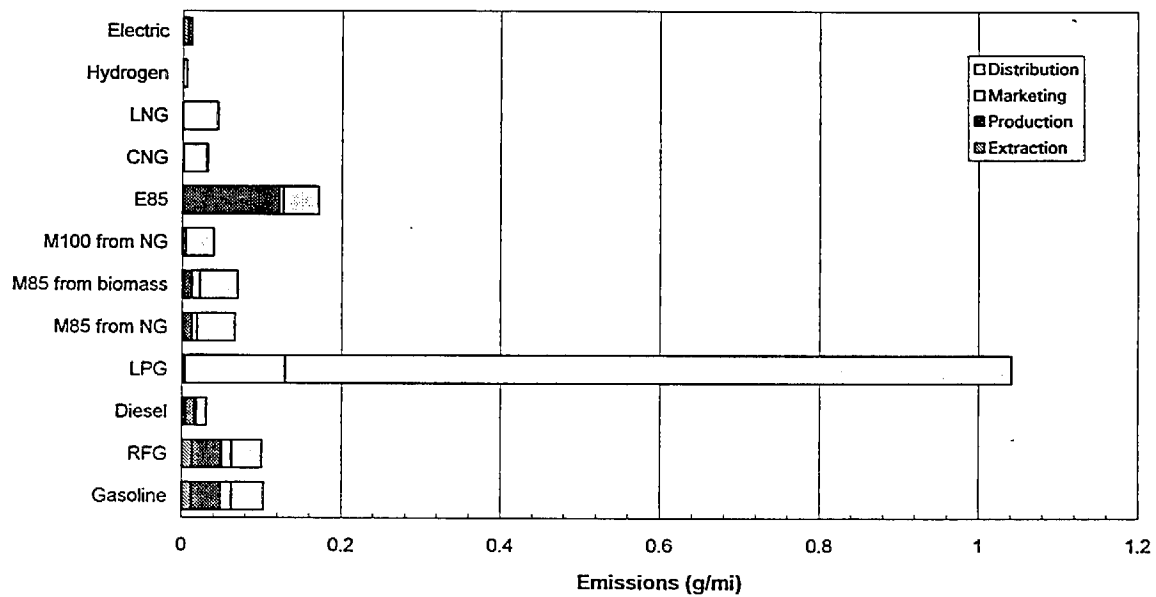


Figure 6-9. Average NMOG, Scenario 1, South Coast (g/mi)

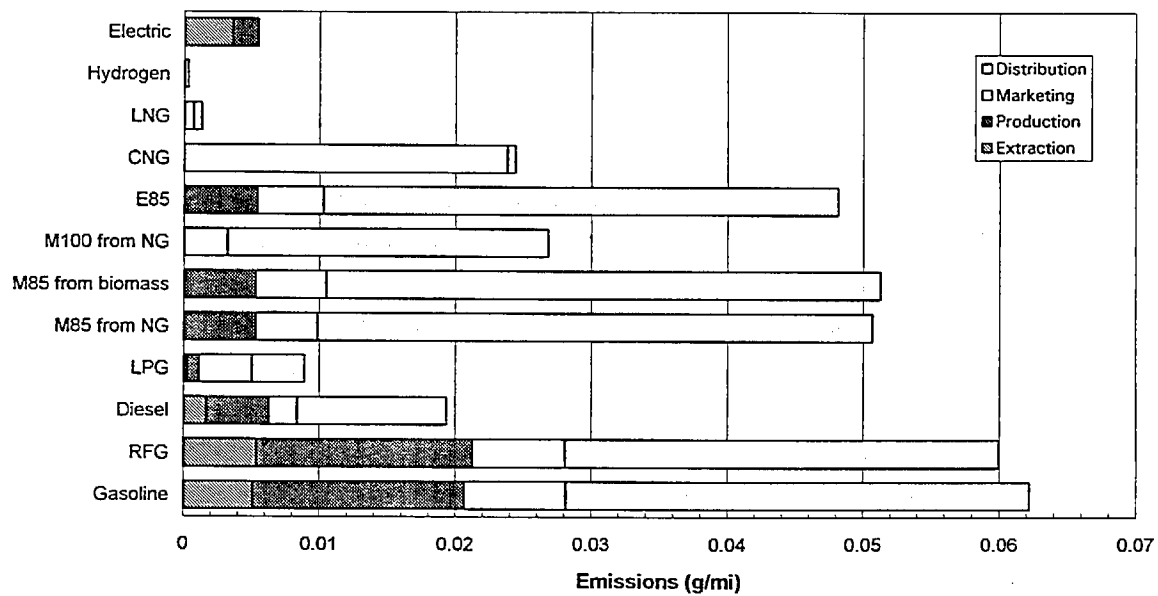


Figure 6-10. Average NMOG, Scenario 2, South Coast (g/mi)

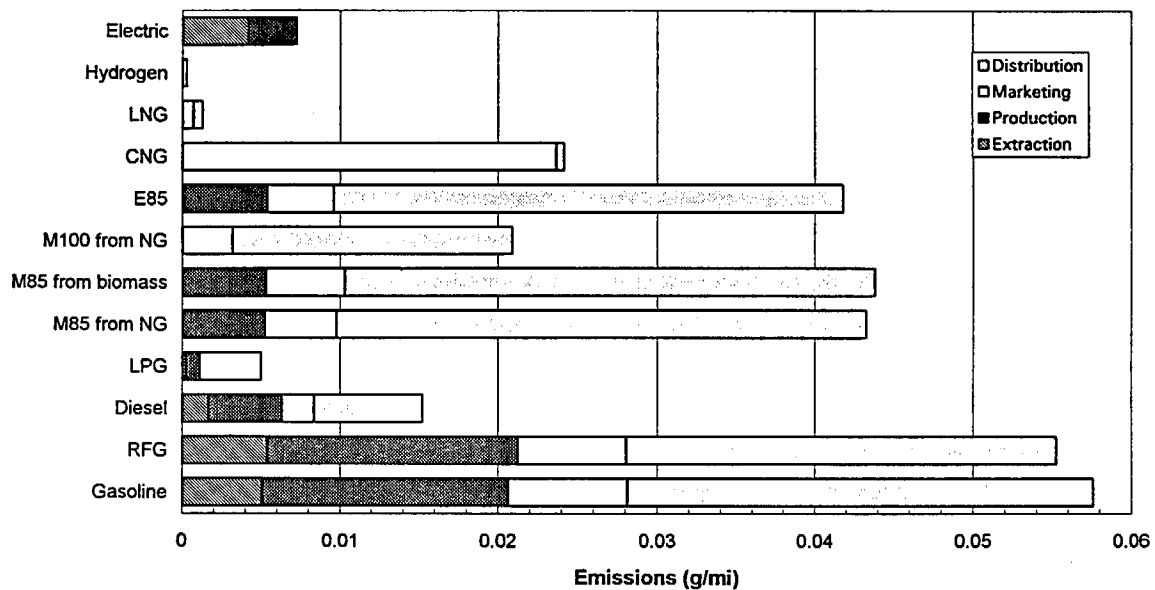


Figure 6-11. Average NMOG, Scenario 3, South Coast (g/mi)

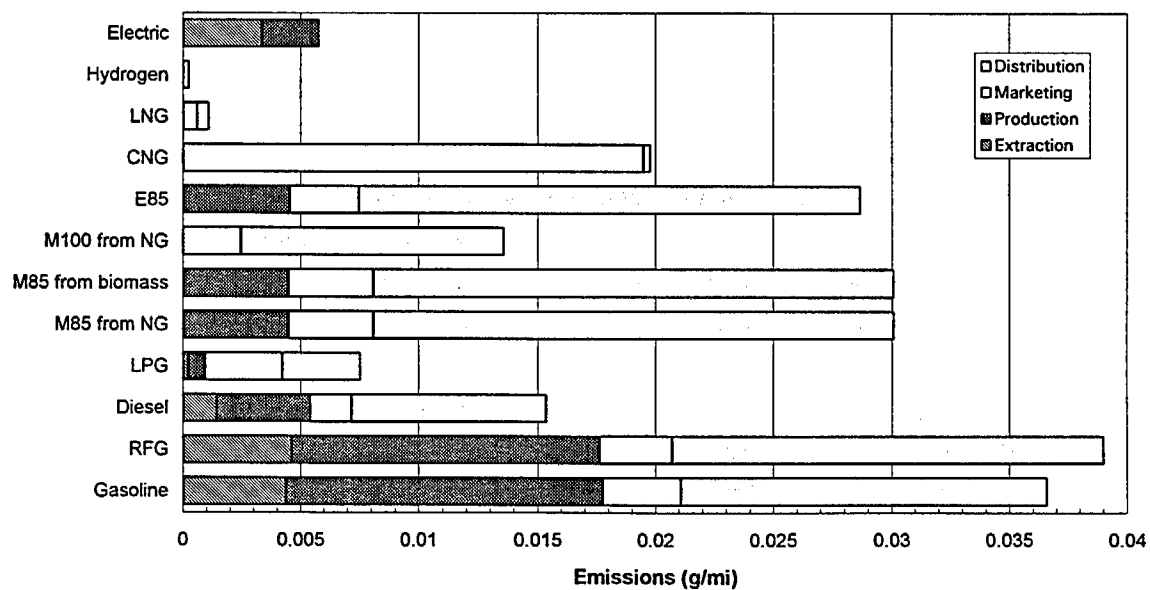


Figure 6-12. Average NMOG, Scenario 4, South Coast (g/mi)

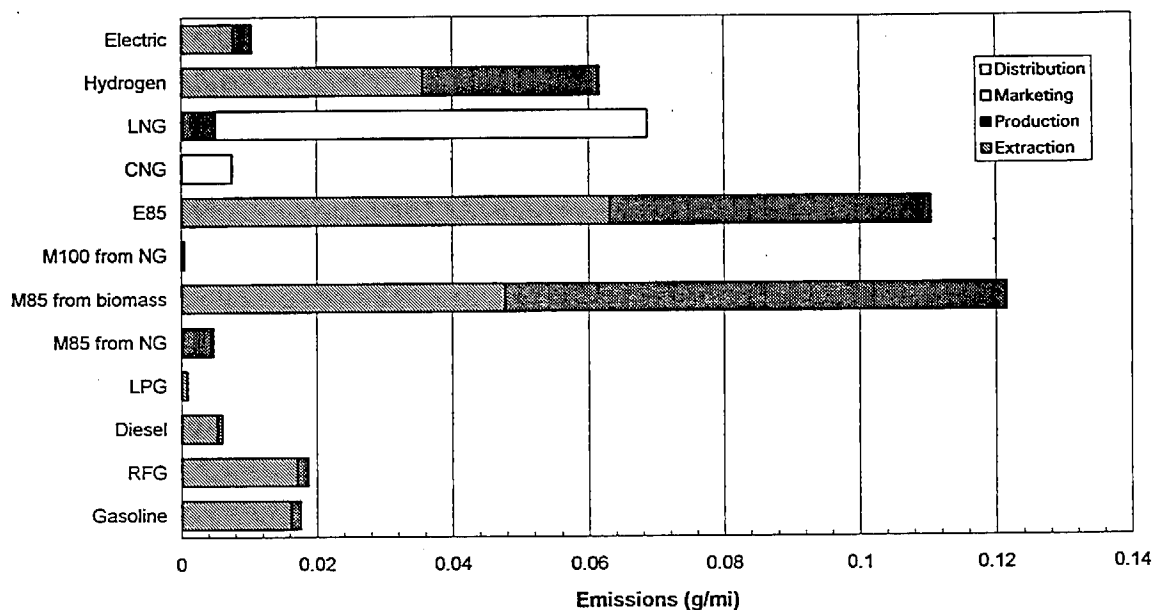


Figure 6-13. Average NMOG, Scenario 3, California excluding South Coast (g/mi)

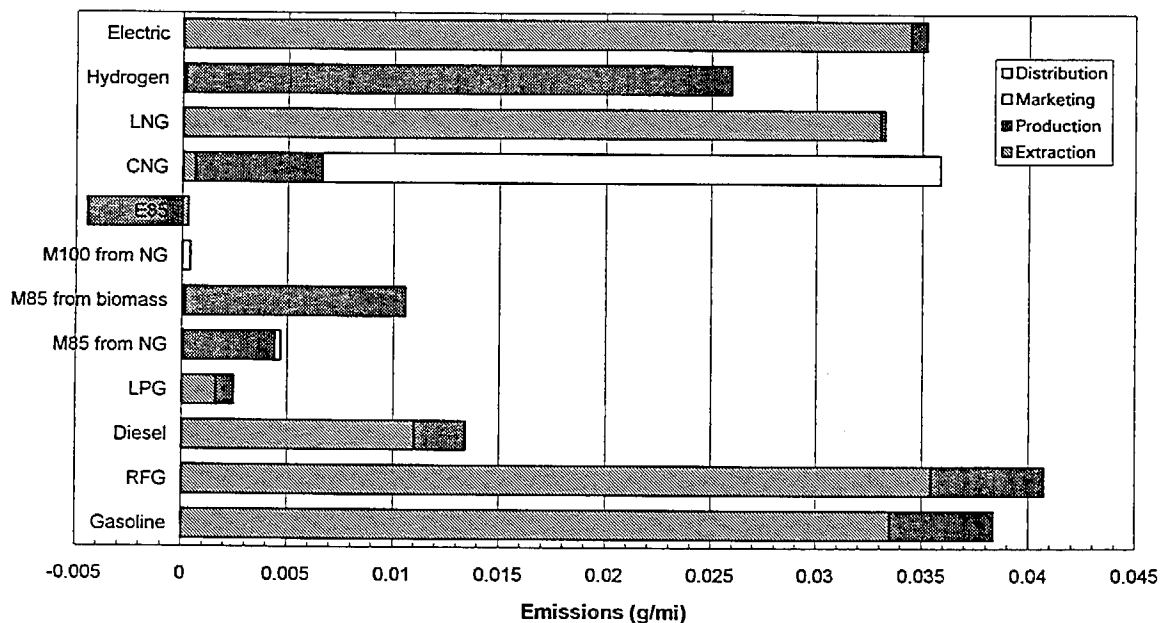


Figure 6-14. Average NMOG, Scenario 3, USA excluding California (g/mi)

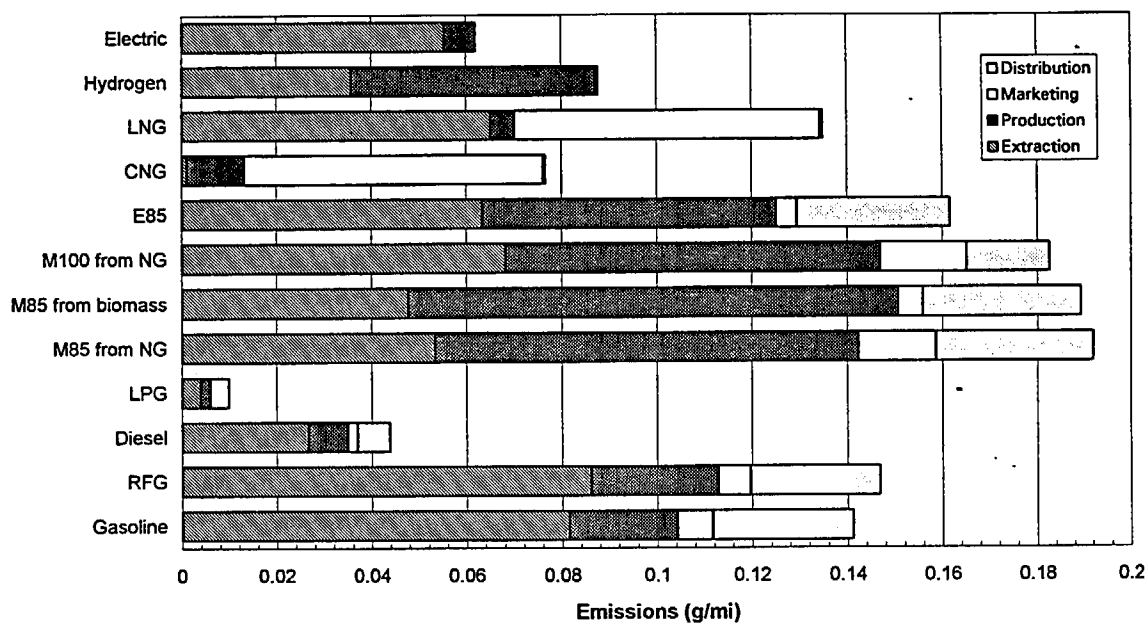


Figure 6-15. Global average NMOG, Scenario 3 (g/mi)

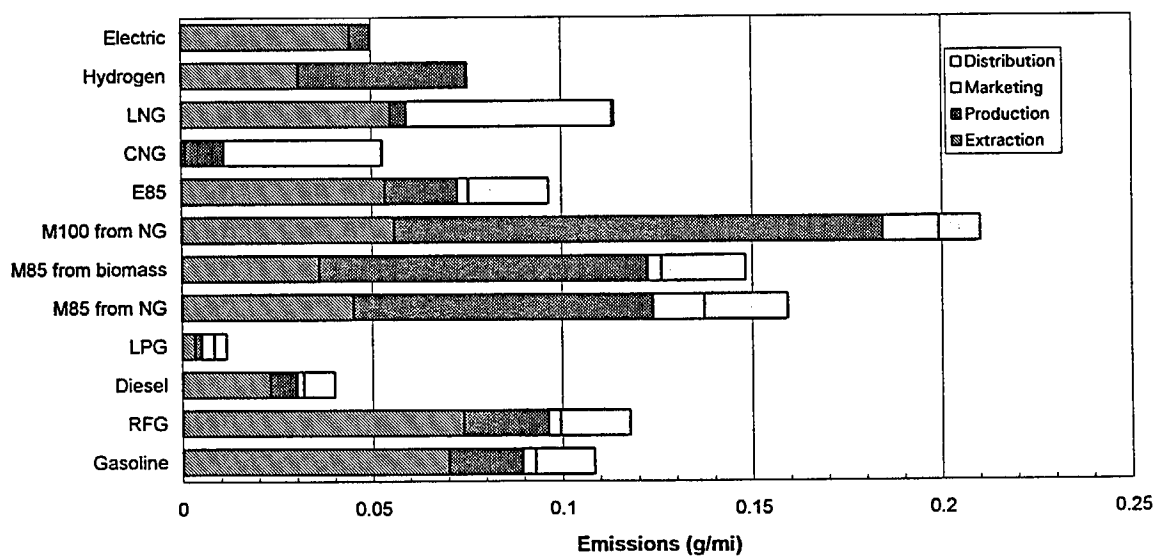


Figure 6-16. Global average NMOG, Scenario 4 (g/mi)

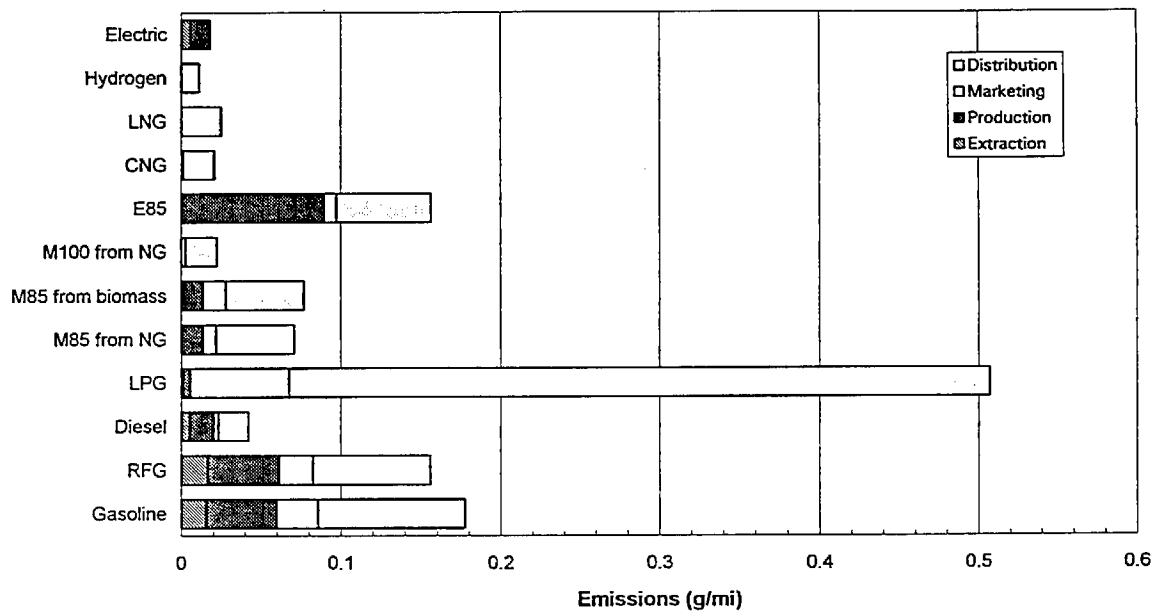


Figure 6-17. Average ozone potential (MIR), Scenario 1, South Coast (g/mi)

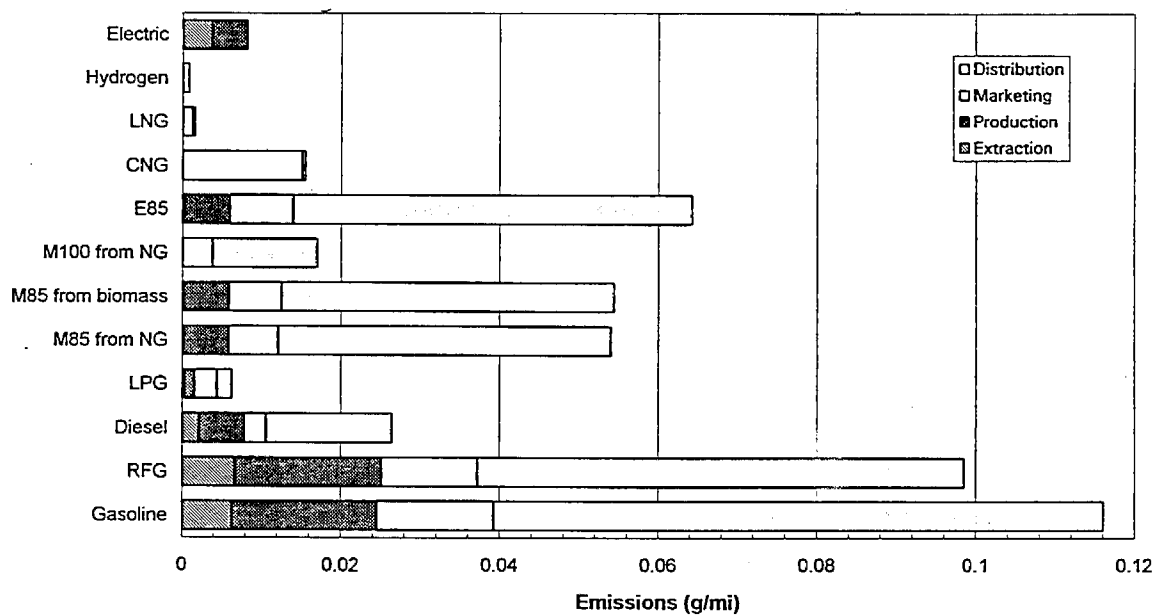


Figure 6-18. Average ozone potential (MIR), Scenario 2, South Coast (g/mi)

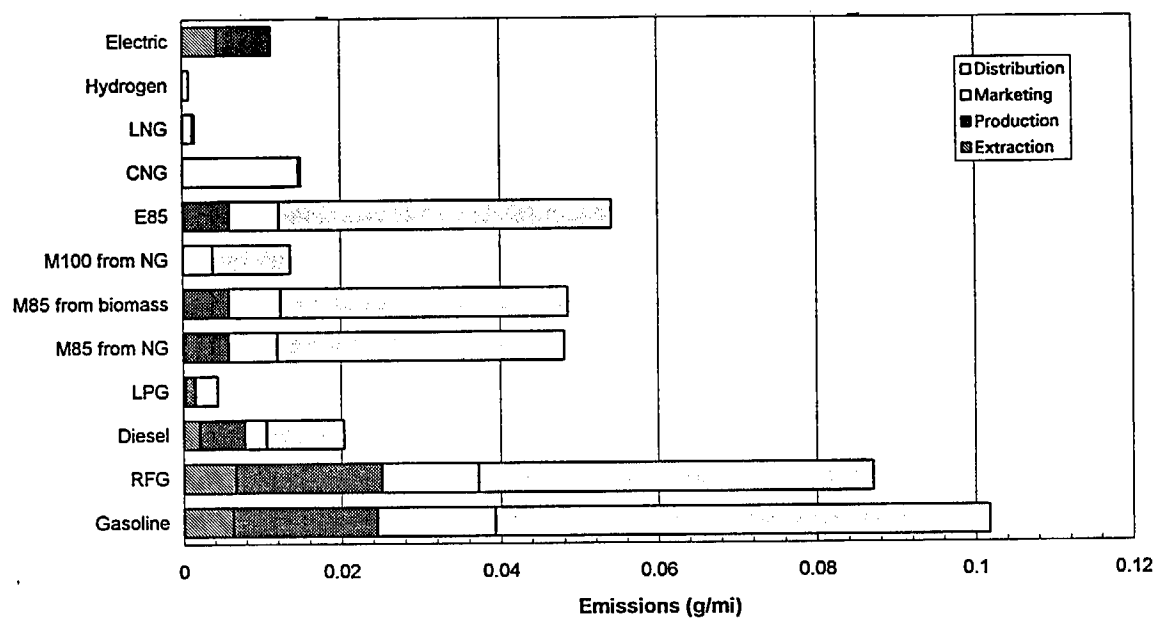


Figure 6-19. Average ozone potential (MIR), Scenario 3, South Coast (g/mi)

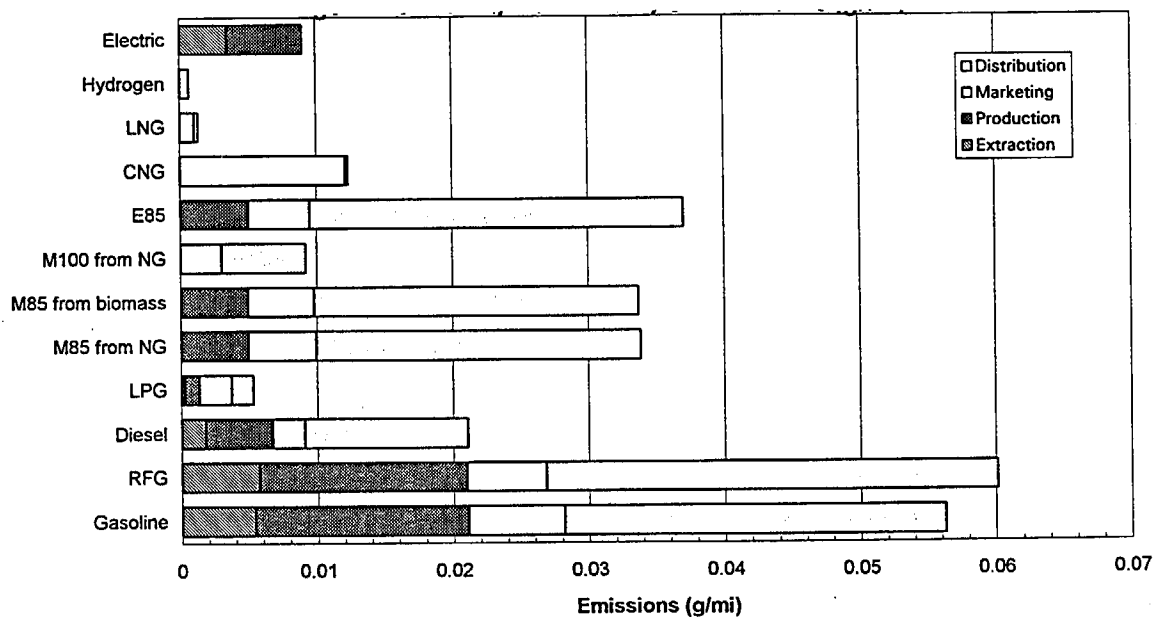


Figure 6-20. Average ozone potential (MIR), Scenario 4, South Coast (g/mi)

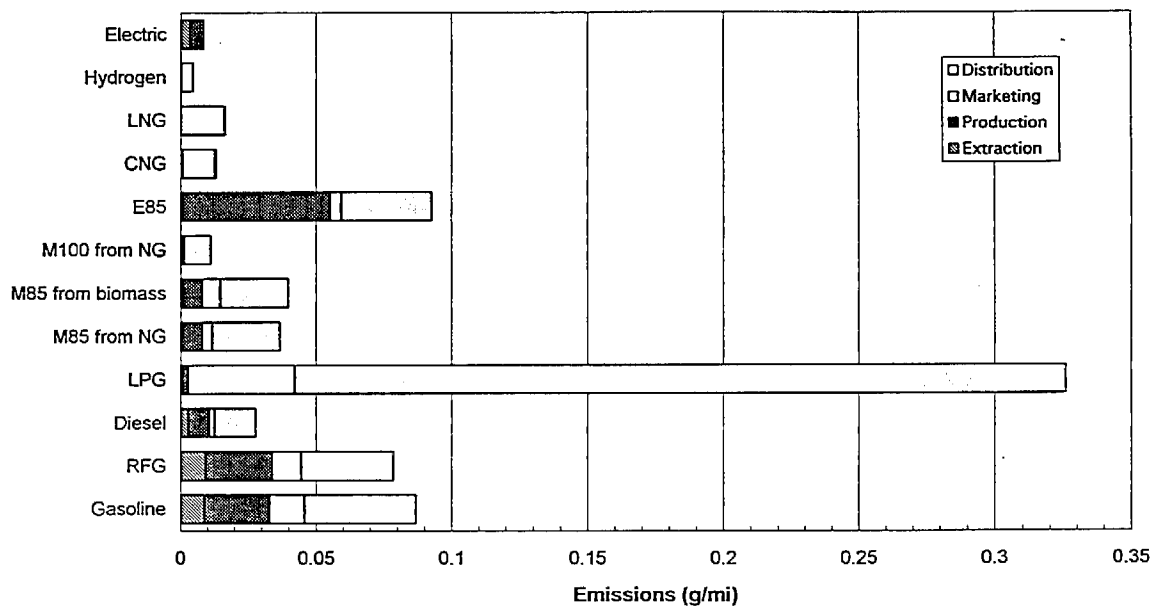


Figure 6-21. Average ozone potential (MOR), Scenario 1, South Coast (g/mi)

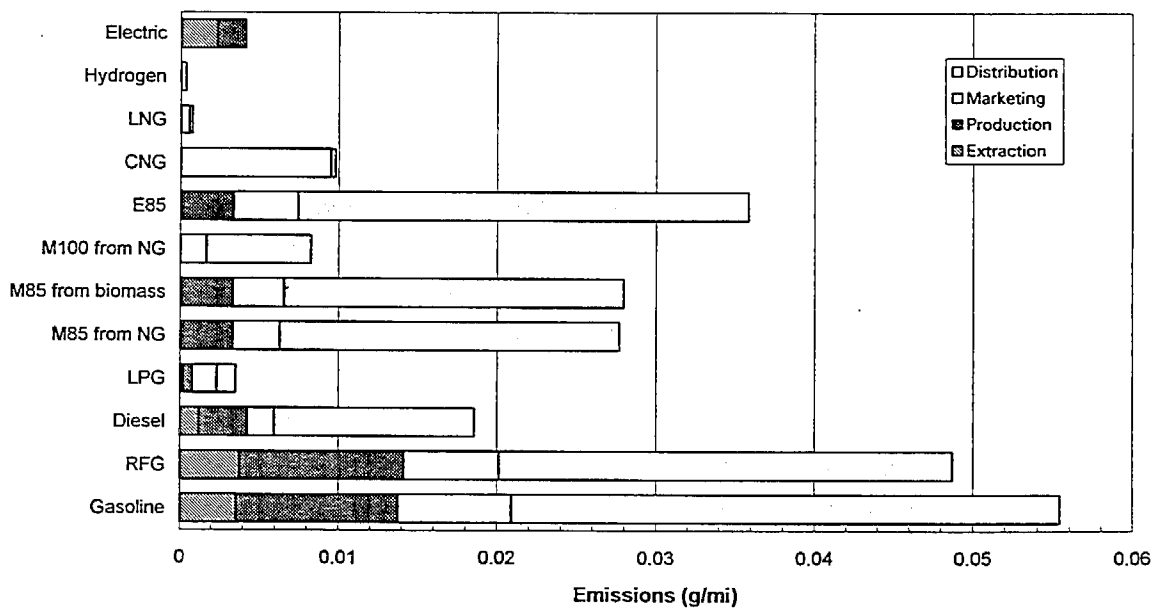


Figure 6-22. Average ozone potential (MOR), Scenario 2, South Coast (g/mi)

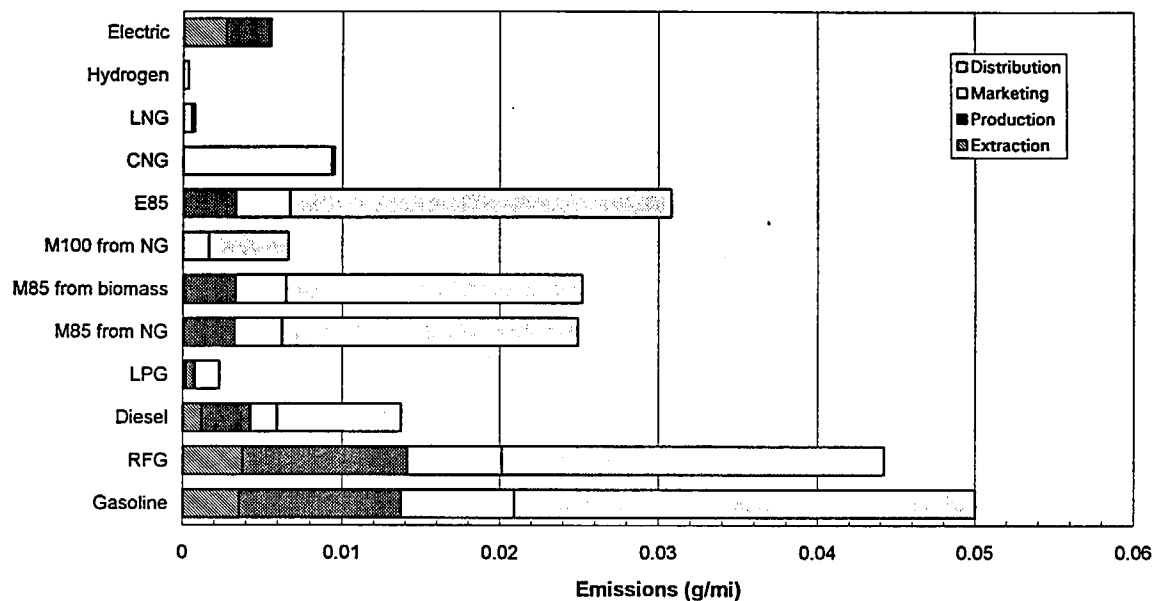


Figure 6-23. Average ozone potential (MOR), Scenario 3, South Coast (g/mi)

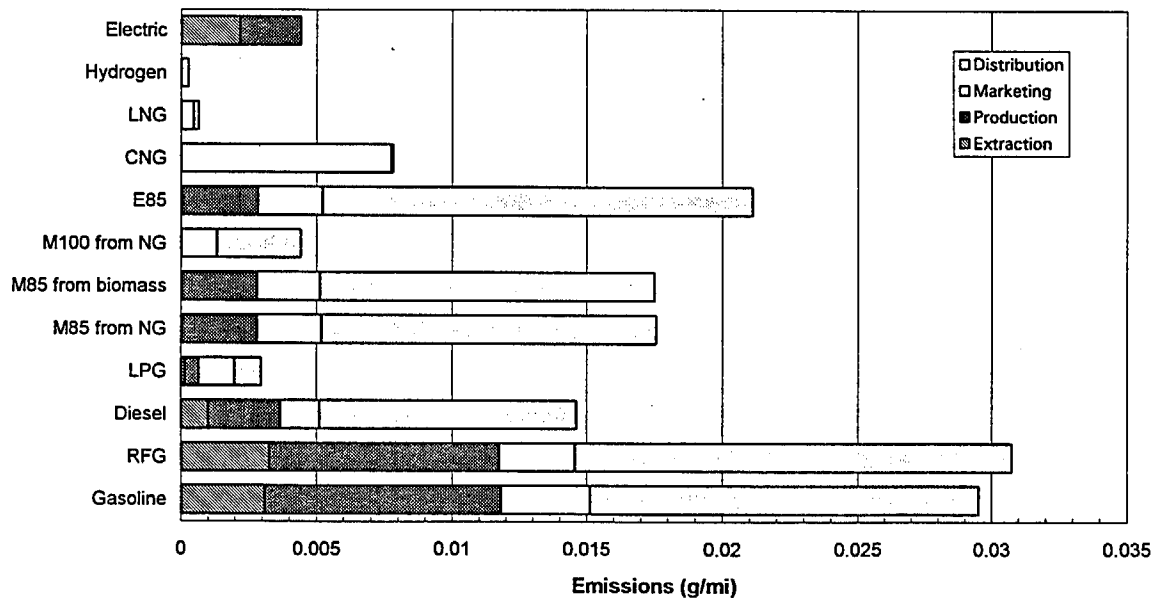


Figure 6-24. Average ozone potential (MOR), Scenario 4, South Coast (g/mi)

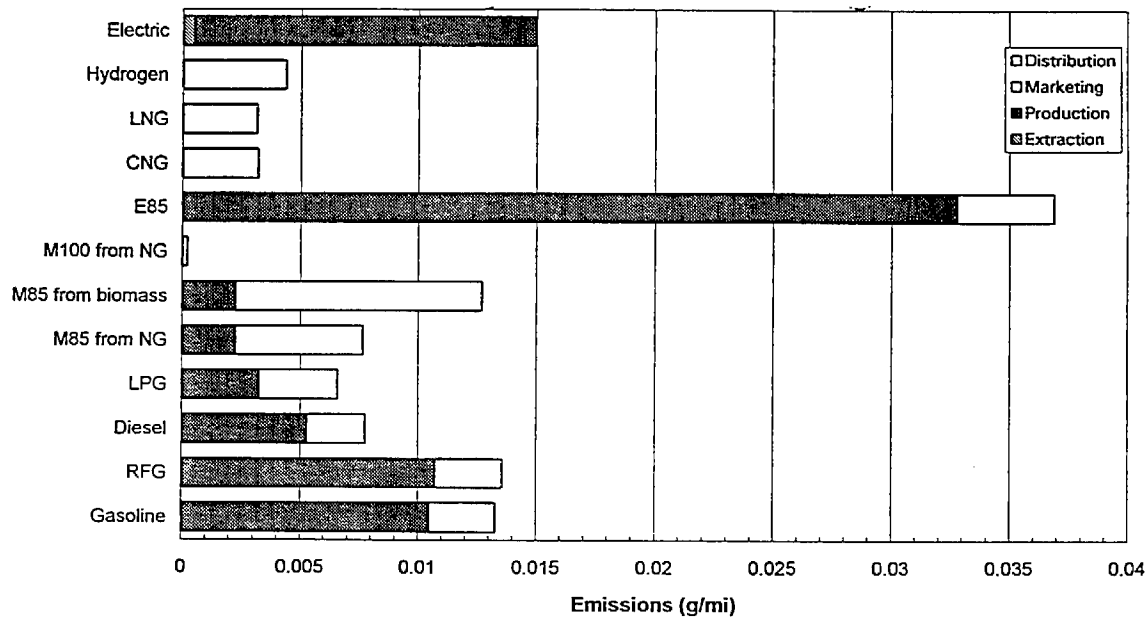


Figure 6-25. Average CO, Scenario 1, South Coast (g/mi)

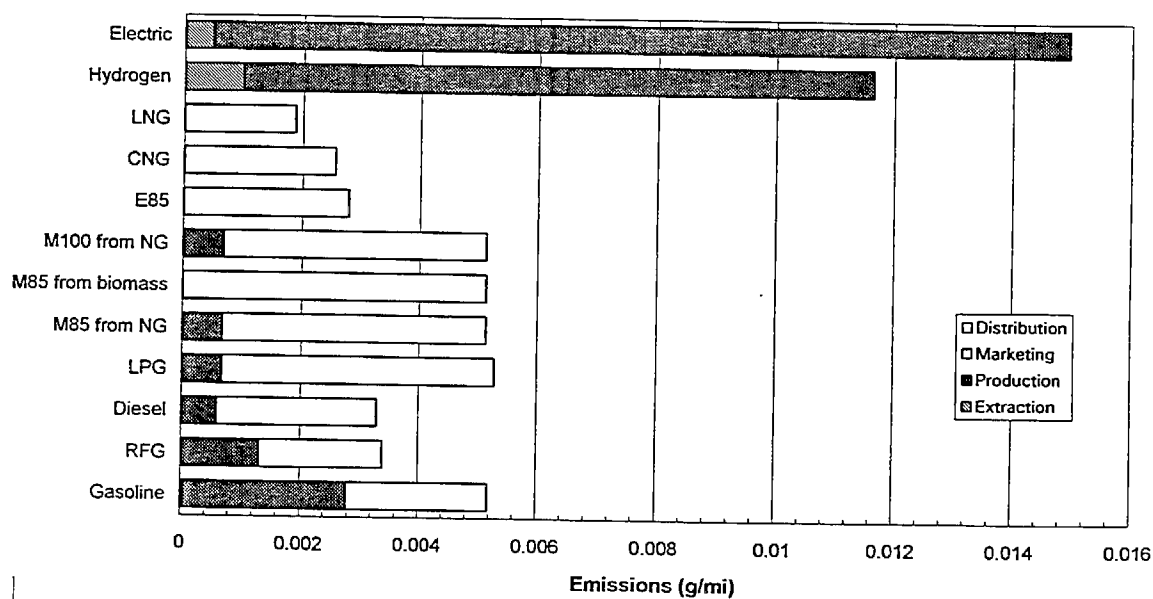


Figure 6-26. Average CO, Scenario 2, South Coast (g/mi)

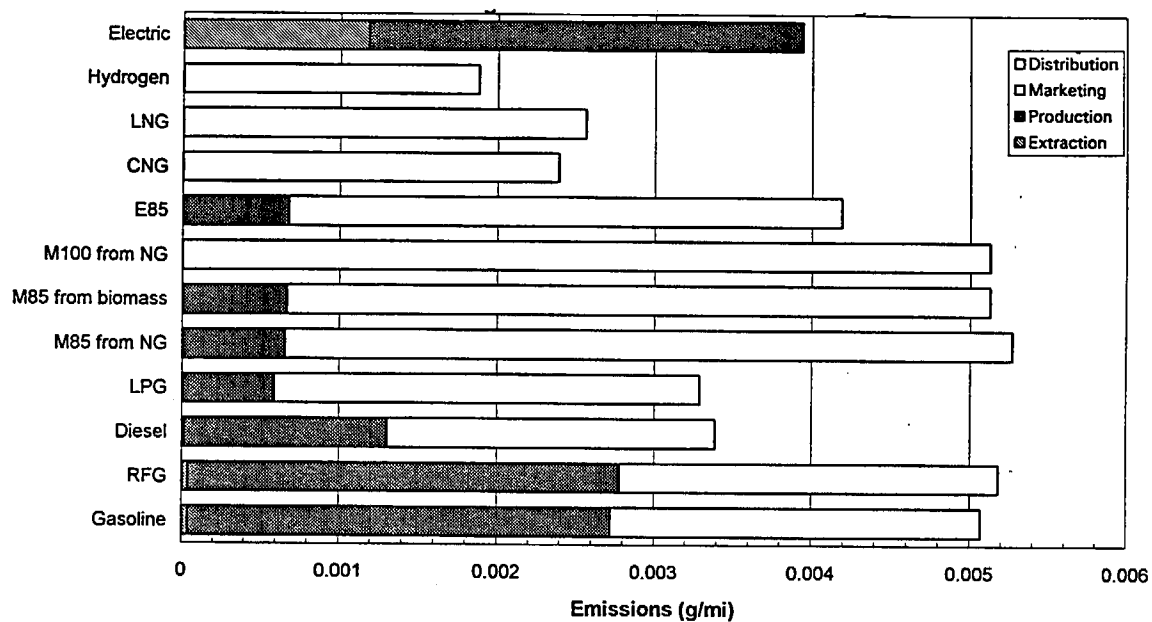


Figure 6-27. Average CO, Scenario 3, South Coast (g/mi)

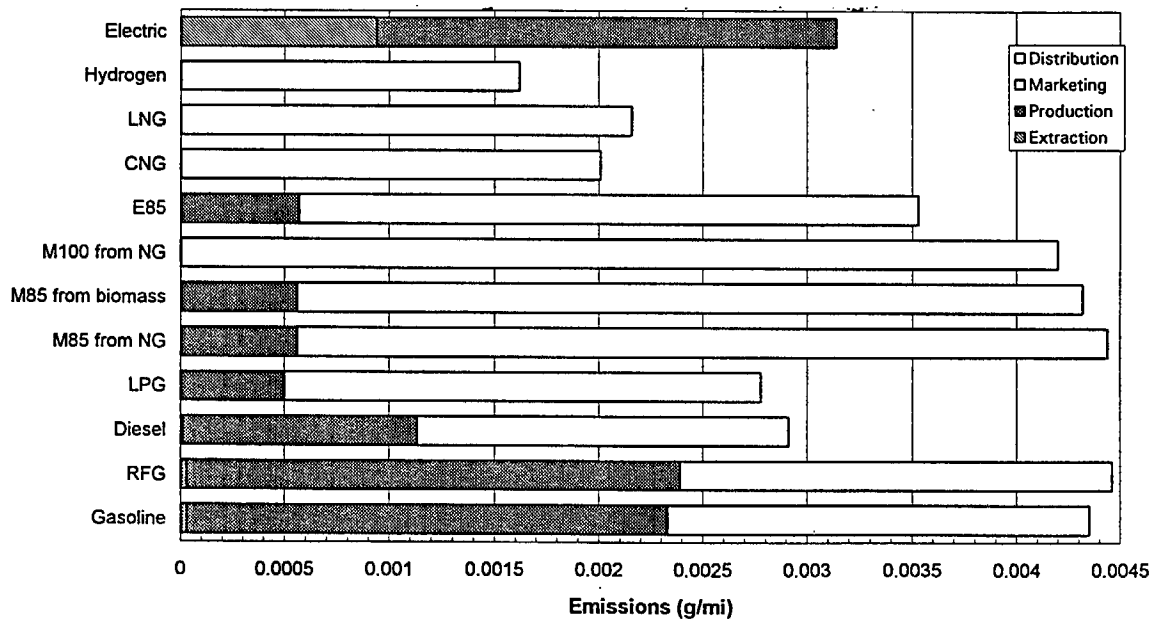


Figure 6-28. Average CO, Scenario 4, South Coast (g/mi)

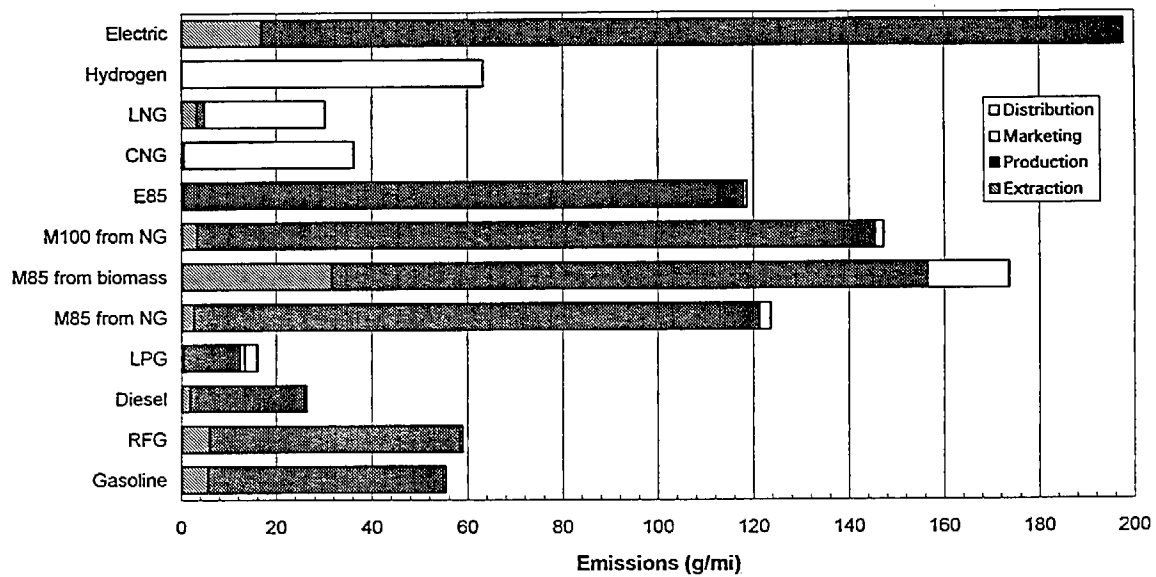


Figure 6-29. Global average CO<sub>2</sub>, Scenario 1 (g/mi)

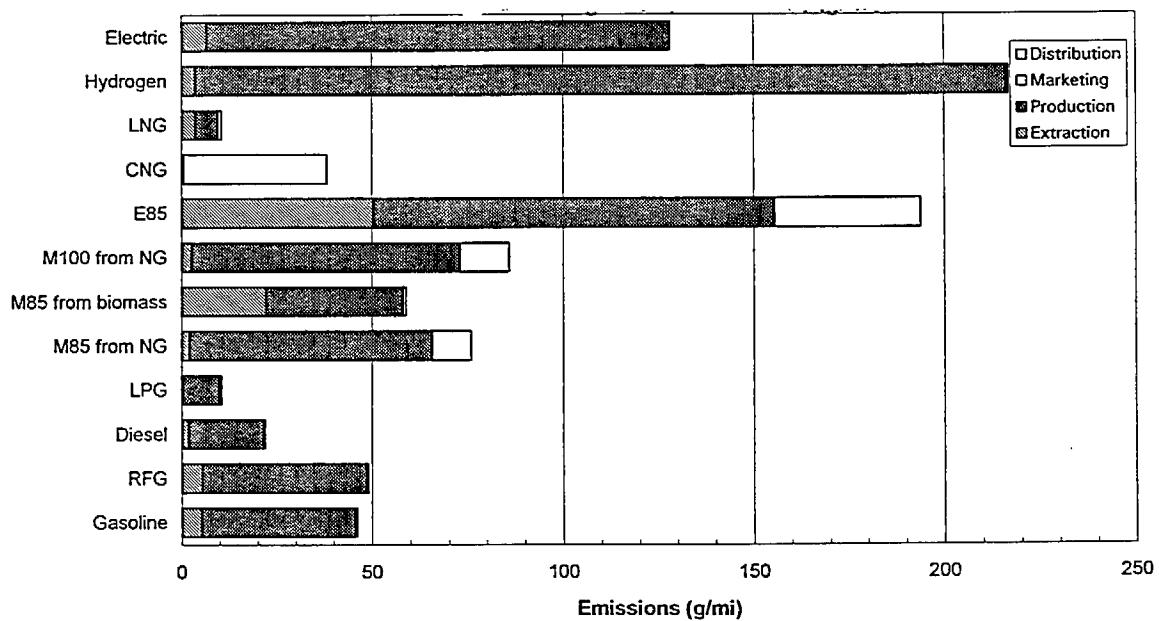


Figure 6-30. Global average CO<sub>2</sub>, Scenario 2 (g/mi)

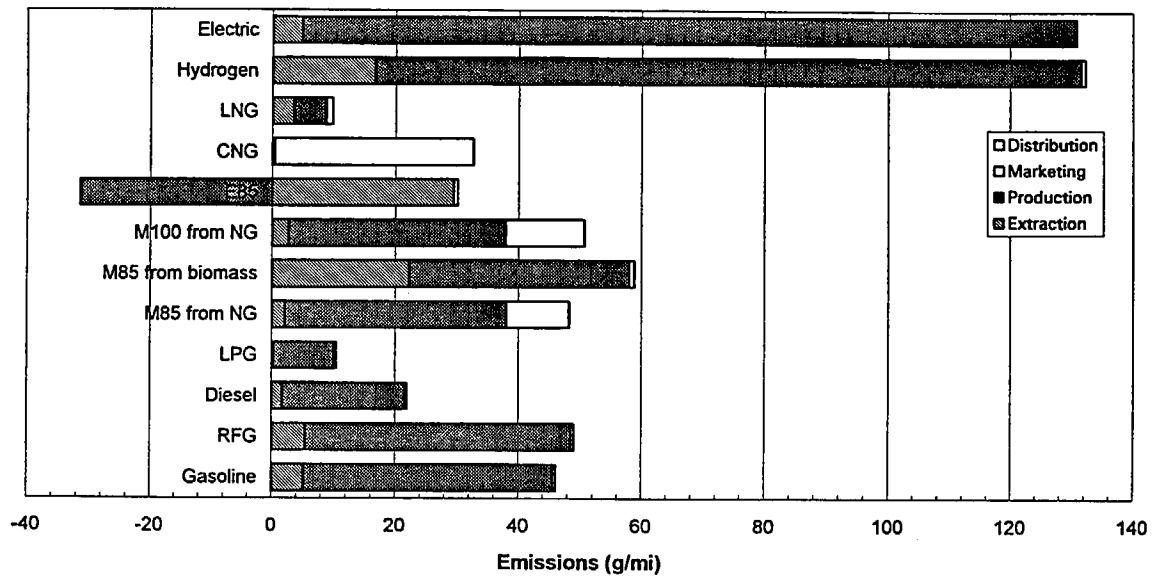


Figure 6-31. Global average CO<sub>2</sub>, Scenario 3 (g/mi)

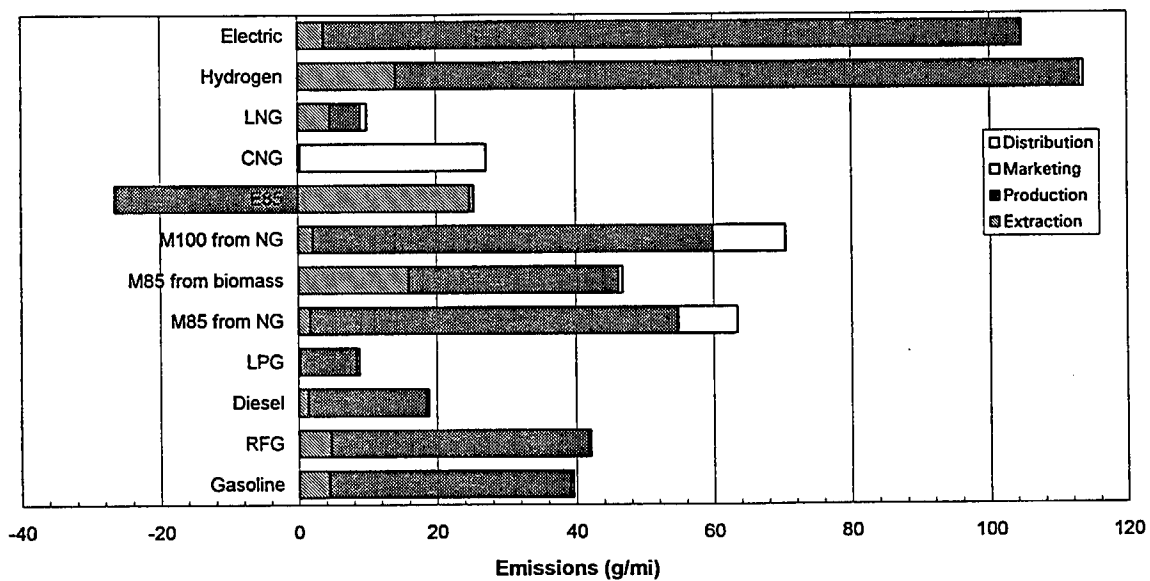


Figure 6-32. Global average CO<sub>2</sub>, Scenario 4 (g/mi)

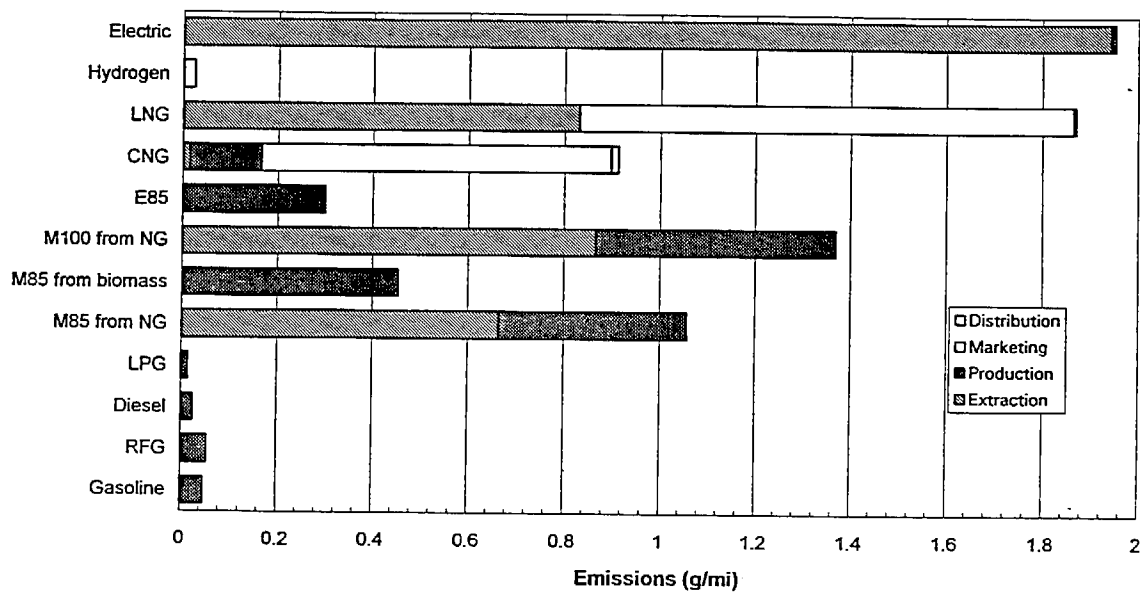


Figure 6-33. Global average CH<sub>4</sub>, Scenario 1 (g/mi)

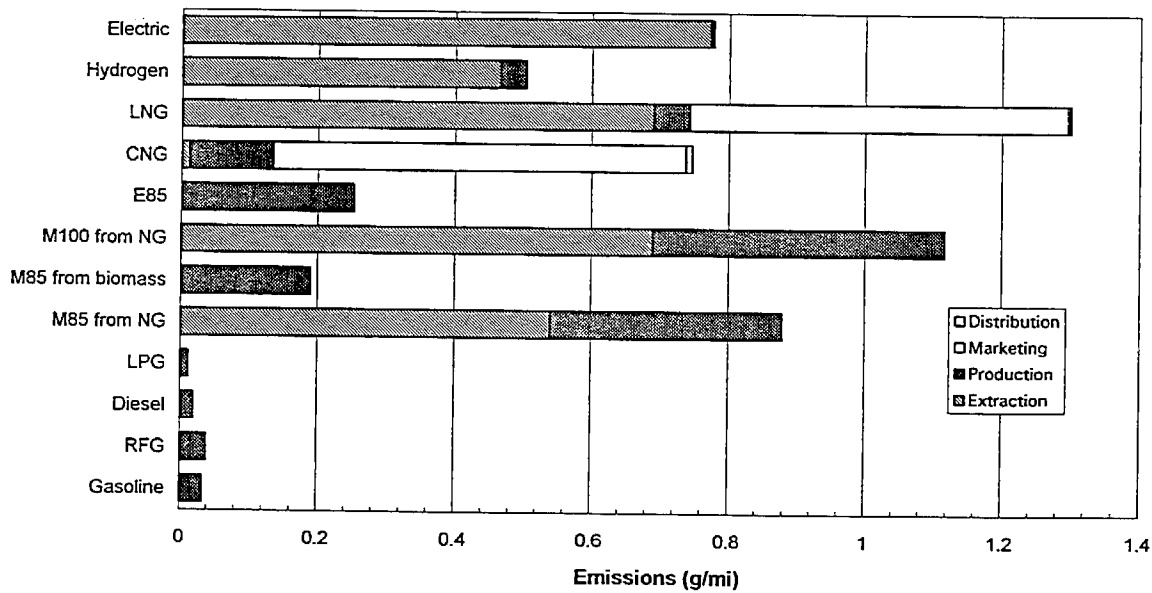


Figure 6-34. Global average CH<sub>4</sub>, Scenario 2 (g/mi)

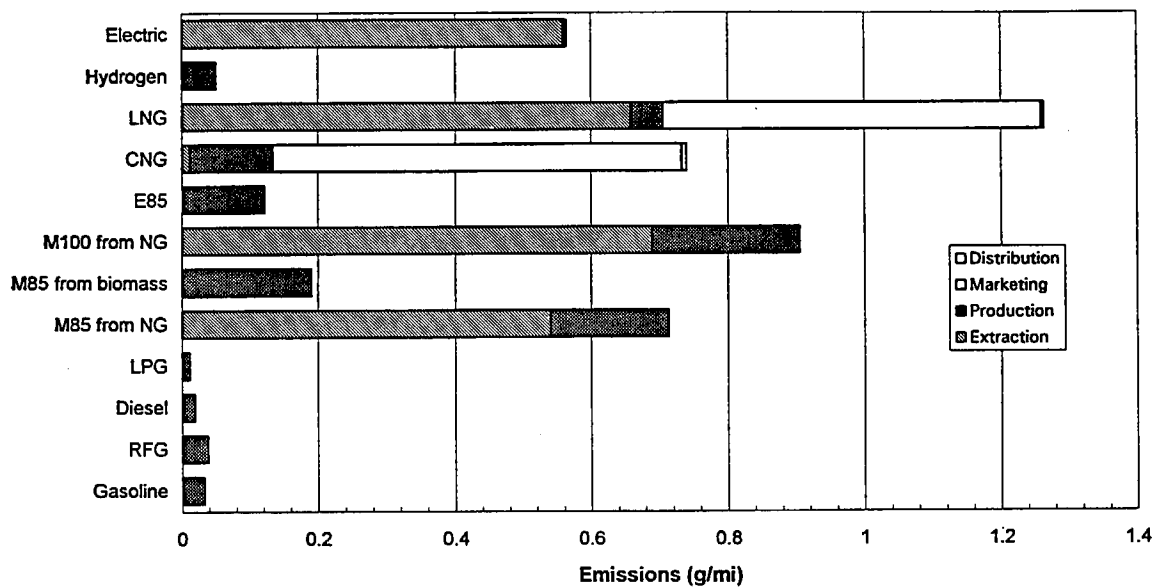


Figure 6-35. Global average CH<sub>4</sub>, Scenario 3 (g/mi)

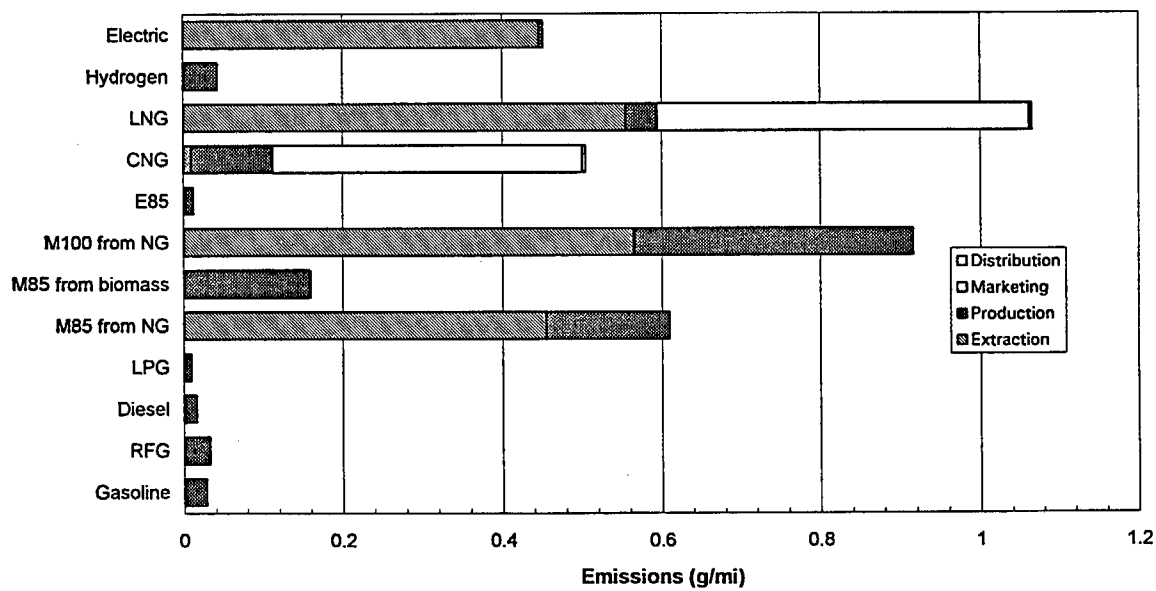


Figure 6-36. Global average CH<sub>4</sub>, Scenario 4 (g/mi)

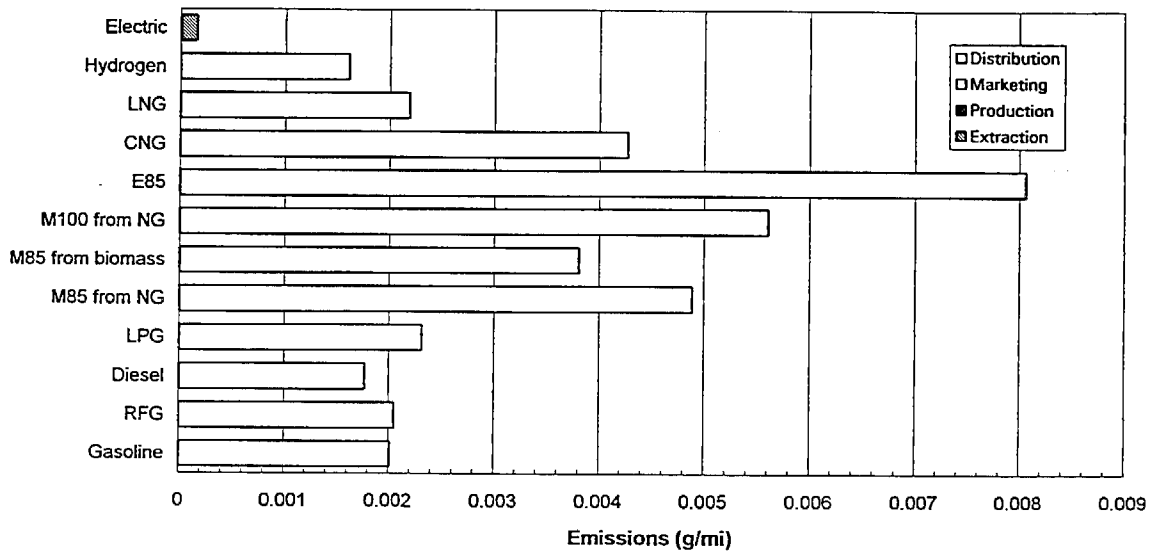


Figure 6-37. Marginal NO<sub>x</sub>, Scenario 2, South Coast (g/mi)

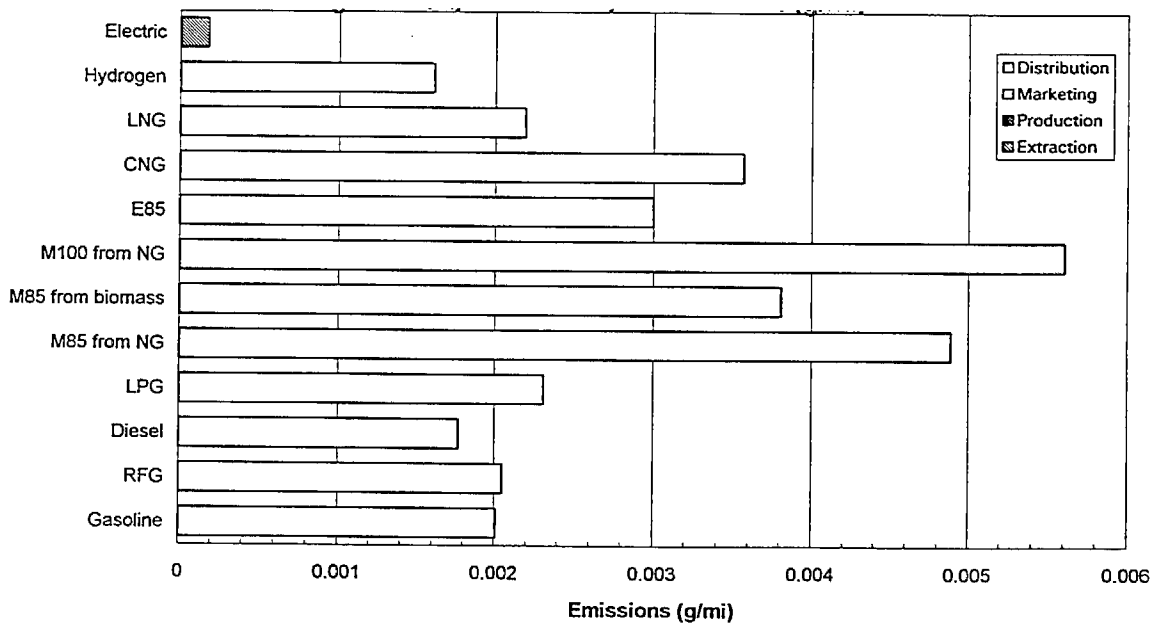


Figure 6-38. Marginal NO<sub>x</sub>, Scenario 3, South Coast (g/mi)

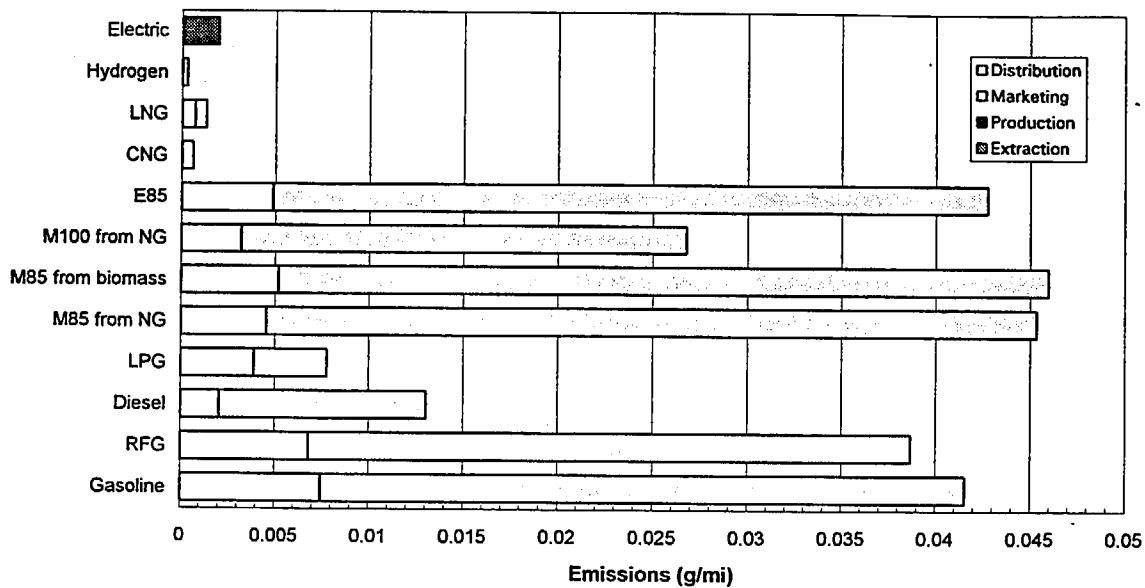


Figure 6-39. Marginal NMOG, Scenario 2, South Coast (g/mi)

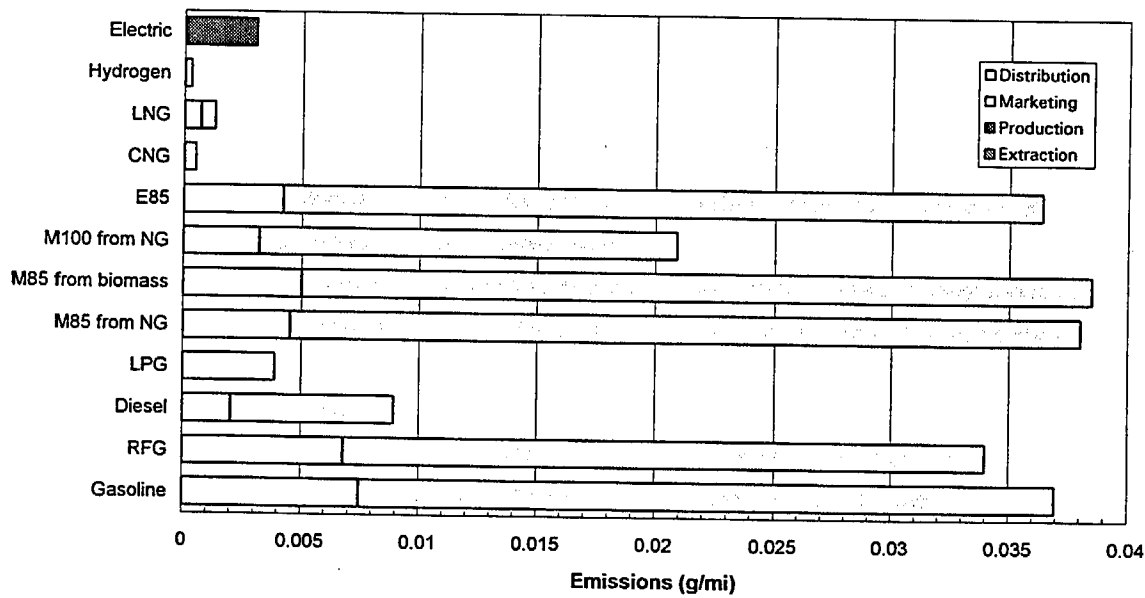


Figure 6-40. Marginal NMOG, Scenario 3, South Coast (g/mi)

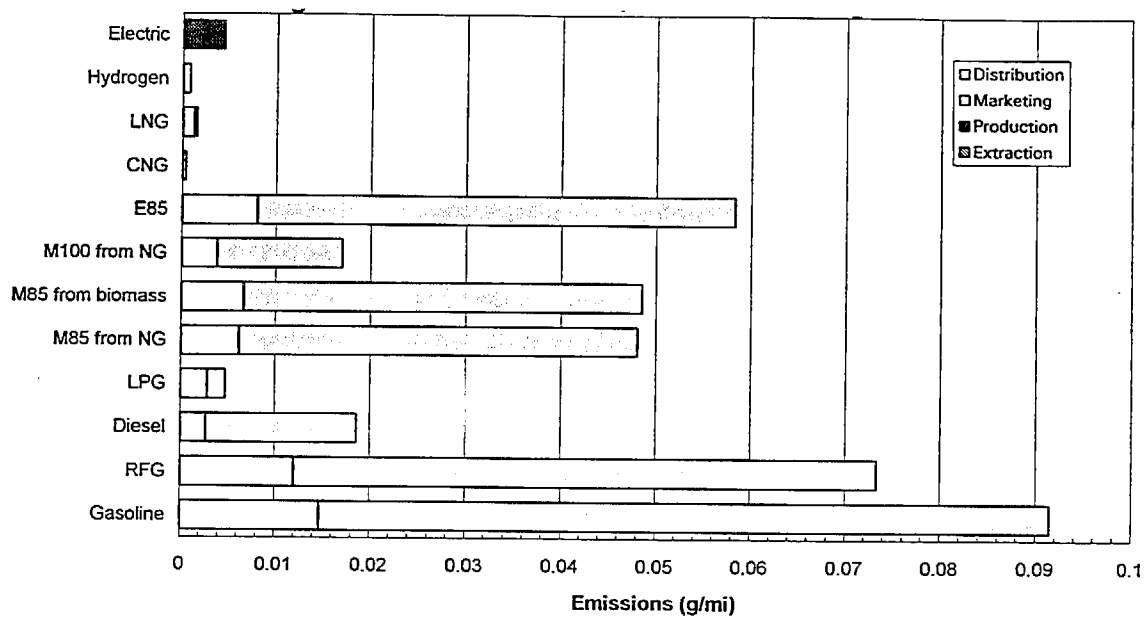


Figure 6-41. Marginal ozone potential (MIR), Scenario 2, South Coast (g/mi)

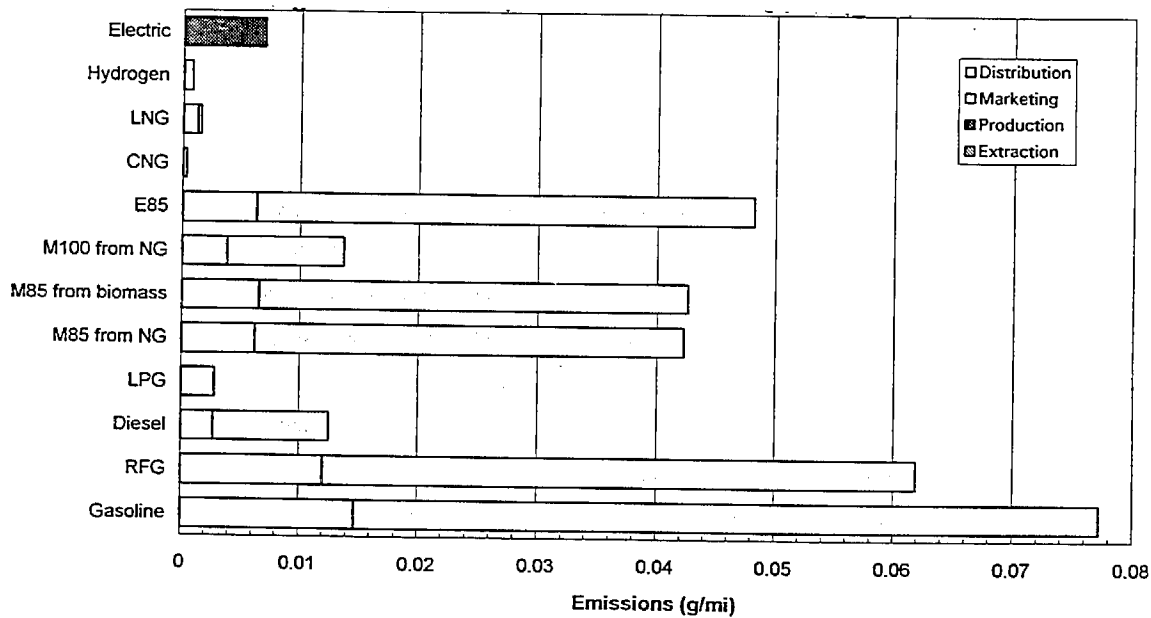


Figure 6-42. Marginal ozone potential (MIR), Scenario 3, South Coast (g/mi)

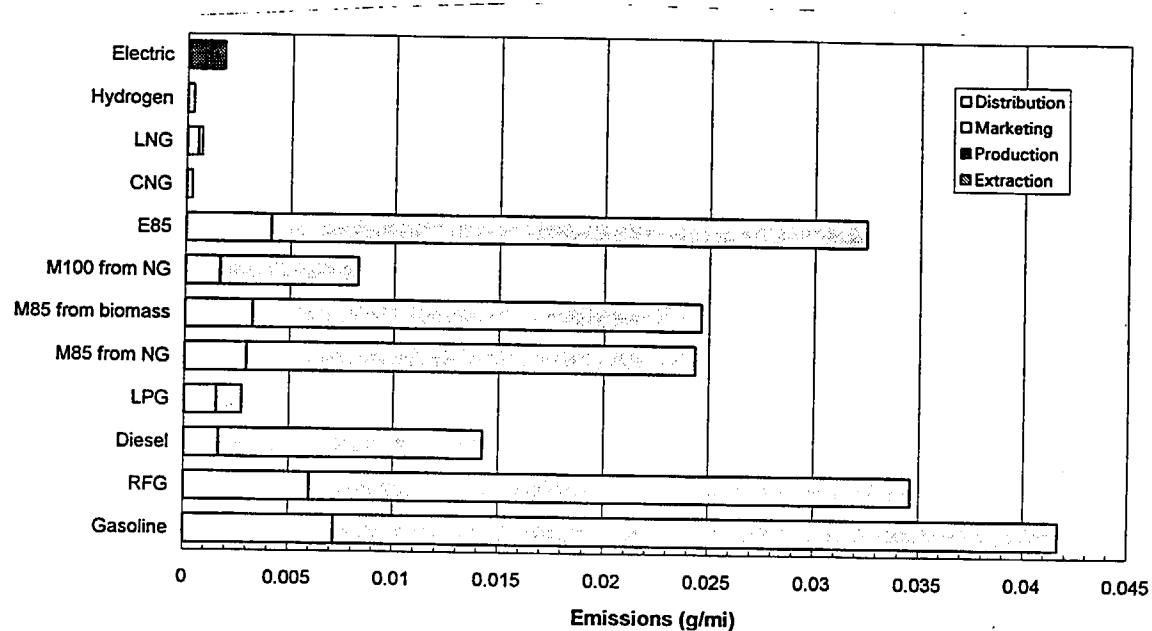


Figure 6-43. Marginal ozone potential (MOR), Scenario 2, South Coast (g/mi)

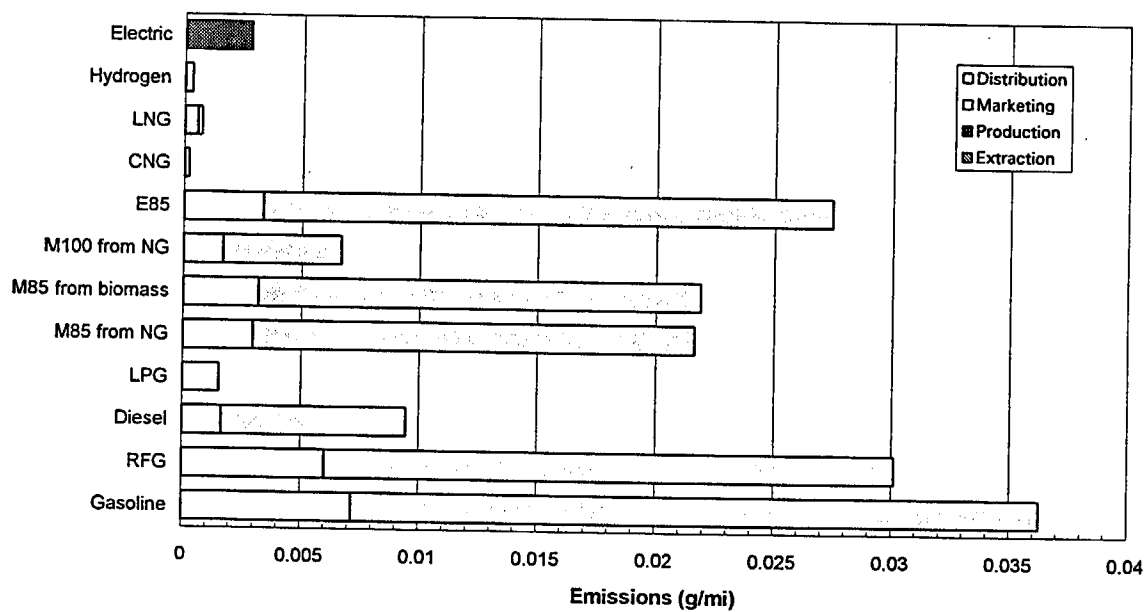


Figure 6-44. Marginal ozone potential (MOR), Scenario 3, South Coast (g/mi)

## 6.4 UNCERTAINTY ANALYSIS

The uncertainty in fuel-cycle emissions is reflected to some extent by Scenarios 2, 3, and 4, which represent specific combinations of emission factors, fuel economy, and fuel infrastructure assumptions. The NMOG values for RFG are 0.06, 0.053, and 0.039 g/mi, respectively. A more thorough estimate of the emissions uncertainty can be determined by examining the range of the emission inputs. Table 6-4 examines the uncertainty in NMOG emissions from RFG production, taking into account more extreme assumptions than those estimates considered in Scenarios 2 through 4. This analysis shows a factor of 4 variability in fuel-cycle emissions, with a minimum emission level of 0.024 g/mi NMOG. These extreme uncertainties are unlikely to all occur at the same time, so a better measure of uncertainty would be an assessment of the uncertainty of independent variables such as those listed in Table 6-5. This table shows the estimated uncertainty for three major independent variables. The uncertainties are different for different fuels, since some fuel options are more sensitive to assumptions regarding emission control while others have less well-defined fuel economy. On balance, the uncertainty in g/mi emissions for the three fuel options in Table 6-5 ranges from 44 to 48 percent. The corresponding range in NMOG emissions for RFG would be 0.035 to 0.079 g/mi.

**Table 6-4. Maximum range in NMOG emissions for RFG  
(within the South Coast Air Basin)**

Average Emissions from RFG Production	NMOG (g/gal)	
	High	Low
Scenario 3 emissions (g/gal)	1.459	1.459
<u>Estimated Uncertainty (g/gal)</u>		
Refueling spillage	+0.127	-0.051
Refueling temperature	+0.025	-0.15
Service station controls	+0.010	-0.10
Other emissions	+0.010	-0.10
Oil refinery fugitives	+0.05	-0.323
Total uncertainty	+0.627	-0.724
Total emissions	2.086	-0.735
Fuel economy (mi/gal)	25	30.25
Fuel-cycle emissions (g/mi)	0.038	0.024

**Table 6-5. Estimated uncertainty in fuel-cycle emissions**

<b>Parameter</b>	<b>Estimated Uncertainty (%)</b>		
	<b>Gasoline</b>	<b>Electric</b>	<b>CNG</b>
Emission factors	41	30	40
Fuel economy	10	25	15
Scenario assumptions	23	20	20
Total uncertainty <sup>a</sup>	48	44	47

<sup>a</sup>Total uncertainty is calculated on a root-mean-square (RMS) basis based on the uncertainties in emission factors, fuel economy, and random and independent scenario assumptions.



## SECTION 7

### CONCLUSIONS AND EMISSION POLICY CONSIDERATIONS

#### 7.1 CONCLUSIONS

Fuel-cycle emissions were evaluated in the context of incremental emissions associated with incremental alternative fuel consumption or gasoline displacement. A moderately small use of alternative fuels would displace gasoline that would be imported into the South Coast Air Basin or allow for additional exports from the South Coast Air Basin, while a more aggressive alternative fuels penetration may lead to a reduction in refinery output. Small increments of alternative fuel use would displace emissions from fuel hauling, vehicle fueling, and possible marine vessels used to import gasoline. On a small scale, other market conditions will influence refinery emissions more substantially than gasoline displacement due to alternative fuel use, leaving the refineries in the South Coast Air Basin operating at capacity. Many alternative fuels would be produced outside the South Coast Air Basin. Their incremental emissions correspond to fuel trucking or distribution and local vehicle fueling.

Electricity for EVs in use in the South Coast Air Basin is generated in the basin, the rest of California, and outside of California. Incremental emissions from power generated in the South Coast Air Basin are limited by several factors. Non-utility power generators in the South Coast Air Basin will not contribute to new power generation as their capacity is already incorporated into the current power generation mix and adding new non-utility capacity is not economically attractive. Furthermore, existing facilities in the South Coast Air Basin could not increase emissions beyond current permit levels and new facilities would need to buy offsets. Power plants in the South Coast Air Basin are subject to RECLAIM which provides a cap on power plant  $\text{NO}_x$  emissions for each utility. The CEC modeled the power generation requirements for baseline power and for EVs with several different power generation scenarios, ranging from 40%, 55%, and 80% EV distribution in the SCAB; 0.24 kWh/mi and 0.35 kWh/mi EV efficiency; and 80/20 vs. 95/5 off-peak/on-peak charging. In the year 2010, CEC projects that SCE will be below its RECLAIM limit while LADWP will be above its RECLAIM limit for CEC's projected mix of power generation. This analysis is based on an assessment of the number of power plants that are equipped with SCR. If a utility is above its RECLAIM limit, it can install SCR on additional power plants or purchase  $\text{NO}_x$  offsets. If a utility is already at its emission cap or in a position where it needs to purchase offsets with respect to South Coast Air Basin RECLAIM, any incremental power generation for EVs will result in no additional  $\text{NO}_x$  emissions in the South Coast Air Basin.

Based on CEC's analysis of the emissions of power plants with respect to their RECLAIM limits,  $\text{NO}_x$  emissions from EVs in the South Coast Air Basin in 2010 will range from 0.008 to 0.012 g/mi. However, the EV power generation will result in zero additional incremental  $\text{NO}_x$  in the South Coast Air Basin due to RECLAIM limits. If a utility's baseline emissions (without EVs) are below its RECLAIM target, the utility would sell credits with the result of no net increase or decrease in

NO<sub>x</sub>. Marginal hydrocarbon emissions from EVs, based on the CEC scenarios, are less than 0.005 g/mi.

Marginal emissions from reformulated gasoline distribution correspond to about 0.03 g/mi of hydrocarbons and 0.002 g/mi of NO<sub>x</sub> from delivery trucks. The rate of alternative fuels penetration would affect marginal emissions from gasoline production. There would be zero impact on refinery NO<sub>x</sub> or hydrocarbon emissions if displaced gasoline matched growth in exports to other states. If gasoline imports were rising to meet vehicle demand, alternative fuels would displace NO<sub>x</sub> emissions corresponding to 0.01 g/mi from marine vessel operations in the South Coast Air Basin. Importing methanol by tanker ship would result in more than 0.01 g/mi of NO<sub>x</sub> from tanker ships due to the fuel's lower energy density. This source of NO<sub>x</sub> would be avoided with ethanol, methanol, and hydrogen produced from biomass as well as CNG and domestic LNG.

The low vapor pressure and ozone potential of methanol and ethanol suggest that the ozone potential from M85 and E85 distribution might be lower than that of gasoline. However, blending with gasoline and increased volumetric fuel consumption results in an ozone potential for distribution emissions somewhat lower than that of reformulated gasoline. The ozone potential from CNG fuel-cycle emissions is minimal. The ozone potential from power generation emissions are also low; however, more data are needed on this source.

NMOG emissions from LPG distribution and fueling are currently very high due to vapor releases from fuel transfer operations. Vapor controls are assumed to be implemented because of emission regulations, and technology improvements will reduce NMOG emissions to levels below those of conventional fuels.

On a global basis, gasoline and methanol from natural gas result in similar CO<sub>2</sub> emissions and substantial NO<sub>x</sub> emissions from tanker ships. CO<sub>2</sub> emissions were lower for CNG, LNG, and electric vehicles, while biomass derived fuels resulted in the lowest incremental CO<sub>2</sub> emissions.

## 7.2 EMISSION POLICY CONSIDERATIONS

Fuel-cycle emissions could be used to manage emissions associated with vehicle operation. Several measures which could affect fuel cycle emissions are listed below. All of these measures would be unpopular with some segments of industry or vehicle users and may also have other consequences which would make them unattractive, unfair, or unlikely to be implemented.

- Cap total emission levels for vehicle fueling stations through the permit process
- Eliminate the generation of saleable emission credits for fuel storage and production facilities that permanently reduce production capacity
- Consider a credit for vehicle exhaust emissions based on fuel-cycle emissions. This approach may lead to unequal treatment of fuels sold within California.

- Tax fuels in proportion to fuel-cycle emissions. This approach would reduce fuel-cycle emissions by creating incentives for less driving and for vehicles with higher fuel economy.
- Determine fuel-cycle emissions for advanced technologies that might compete with EVs for ZEV status



## SECTION 8

### BIBLIOGRAPHY

Acurex Environmental Corporation, "Clean Coal Fuels — Alternate Fuel Strategies for Stationary and Mobile Engines," prepared for the California Energy Commission.

Acurex Environmental, "On-Board Heavy-Duty Tank Mobile Emission Testing in Support of Mobile Source Emission Inventories and On-Board Emissions Factor for Diesel Bus," ARB Contract 92-924, Final Report, March 1996.

Adler, D., D. Korotney, T. L. Sprik and S. Stepanek; "Alternative Transportation Fuels and the Greenhouse Effect," U.S. Environmental Protection Agency, June 1992.

American Gas Association, Energy Analysis, EA 1991-7, 1991.

American Gas Association, "NGV Industry Strategy," May 1995. (Natural Gas Vehicle Coalition, Gas Research Institute, American Association)

American Gas Association, "NGV Industry Strategy," Appendix Modeling Assumptions and Results, May 1995. (Natural Gas Vehicle Coalition, Gas Research Institute, American Association)

American Gas Association, "New Pipeline Construction, Status Report Year-End 1992," Catalog No. F00102, February 1993.

American Petroleum Institute, "Net Energy Analysis of Alcohol Fuels," API Publication No. 4312, November 1979.

American Petroleum Institute, "Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations," API Publication No. 4589, December 1993.

American Petroleum Institute, "Development of Fugitive Emission Factors and Emission Profiles for Petroleum Marketing Terminals," Volume I : Text, API Publication No. 4588, May 1993.

American Petroleum Institute, "Development of Fugitive Emission Factors and Emission Profiles for Petroleum Marketing Terminals," Volume II : Appendices, API Publication No. 45881, May 1993.

American Petroleum Institute, "Study of Refinery Fugitive Emissions from Equipment Leaks," Volumes I & II, API Publication No. 4612, April 1994.

American Petroleum Institute, "Study of Refinery Fugitive Emissions from Equipment Leaks," Appendices, API Publication No. 4613, April 1994.

Amoco-U.S. EPA, "Pollution Prevention Project", Executive Summary, Yorktown, Virginia, December 1991 (Revised May 1992).

ARB, "Establishment of Reactivity Adjustment Factors, Supplement to Initial Statement of Proposed Rulemaking (Staff Report), Amendments to the Low-Emission Vehicle Program," Mail Out #92-59, California Air Resources Board, Mobile Source Division, November 13, 1992.

Asregadoo, R., personal communications, October 3, 1994.

Asregadoo, R., "Gasoline Dispensing Facilities," Section 1-8, Revised March 1992 in "Methods for Assessing Area Source Emissions in California, ARB September 1991.

Auto/Oil Air Quality Improvement Research Program, Coordinating Research Council, "Emissions and Air Quality Modeling Results from Methanol/Gasoline Blends in Prototype Flexible/Variable Fuel Vehicles," Technical Bulletin No. 7, January 1992.

Auto/Oil Air Quality Improvement Research Program, Coordinating Research Council, "Emissions from Methanol Fuels and Reformulated Gasoline in 1993 Production Flexible/Variable Fuel and Gasoline Vehicles," Technical Bulletin No. 13, August 1994.

Auto/Oil Air Quality Improvement Research Program, Coordinating Research Council, "Estimated Costs of Modifying Gasoline Parameters," Economic Bulletin No. 2, January 1992.

Auto/Oil Air Quality Improvement Research Program, Coordinating Research Council, "Initial Mass Emissions from Reformulated Gasolines," Technical Bulletin No. 1, December 1990.

Auto/Oil Air Quality Improvement Research Program, Coordinating Research Council, "Reactivity Estimates for Reformulated Gasoline and Methanol Gasoline Mixtures," Technical Bulletin No. 12, June 1993.

Auto/Oil Air Quality Improvement Research Program, "Initial Mass Emissions from Reformulated Gasolines," Technical Bulletin No. 1, Coordinating Research Council, December 1990.

Auto/Oil Air Quality Improvement Research Program, "Emissions and Air Quality Modeling Results from Methanol/Gasoline Blends in Prototype Flexible/Variable Fuel Vehicles," Technical Bulletin No. 7, Coordinating Research Council, January 1992.

Auto/Oil Air Quality Improvement Research Program, "Estimated Costs of Modifying Gasoline Parameters," Economic Bulletin No. 2, Coordinating Research Council, January 1992.

Balles, E., J. M. Bentley, P. Teagan, D. Walls and T. Parish, "Impact of Electric Vehicles on CO<sub>2</sub> Emissions," prepared for EG&G Idaho, Inc. under Subcontract C91-103441 and for the Idaho National Engineering Laboratory, U.S. Department of Energy and Assistant Secretary for Conservation and Renewable Energy under DOE Contract No. DE-AC07-76ID01570, May 1992

Barron, F. R., Cryogenic Systems, Second Edition, Oxford University Press, Inc., New York, 1985.

Bechtel, Inc., "California Fuel Methanol Cost Study, Final Report, Volume II," December 1988.

Benz, A. D., B. D. Degen, and J. R. McKibbin, "Cogeneration in the Petroleum Refinery," Chemical Engineering Progress, October 1986, pp. 21-27.

Bockris, J. O., Energy, The Solar Hydrogen Alternative, The Flinders University of South Australia, John Wiley and Sons, 1975.

Boekhaus, K. L., et al., "Clean Fuels Report 91-02, Impact of EC-1 Reformulated Gasoline on Emissions and Their Reactivity in Five 1989 Cars," ARCO Products Company, February 15, 1991.

Bohi, D.R., "Low Emission Vehicle Program Applications of San Diego Gas & Electric Co., Southern California Gas Co., Southern California Edison Co. and Pacific Gas and Electric Company," Prepared Testimony of Douglas R. Bohi on behalf of the Western States Petroleum Association, May 2, 1994.

Booz, Allen, and Hamilton, Inc., "Projected Heavy Crude Refining in California and Options for Disposal of Residual Oil Surplus," prepared for the California Energy Commission, June 1981.

Bracha, M., et al., "Large Scale Hydrogen Liquefaction in Germany," International Journal of Hydrogen Energy, Vol. 19, No. 1, January 1994.

Bremnes, K., "Global Distribution of NO<sub>x</sub> and SO<sub>2</sub> Methods of Calculation," EMEP Workshop on Emission from Ships, Oslo, June 1990.

Brown, R., "Refining Industry Study," presentation to the California Energy Commission, March 29, 1994.

Brownlow, A. D., J. K. Brunner and J. S. Welstand "Changes in Reid Vapor Pressure of Gasoline in Vehicle Tanks as the Gasoline is Used," SAE paper 892090, Society of Automotive Engineers, September 25-28, 1989.

Caldwell, J. H. Jr., "Refinery Process and Reformulated Gasoline," SCAQMD, January 28, 1991.

California Air Resources Board (ARB), "A Report to the Legislature on Gasoline Vapor Recovery systems for Vehicle Fueling at Service Stations (Stage II Systems)," March 1983.

California Air Resources Board (ARB), "California Phase 2 Reformulated Gasoline Specifications — Proposed Regulations for California Phase 2 Reformulated Gasoline, Technical Support Document," October 4, 1991.

California Air Resources Board (ARB), "Reformulated Gasoline: Proposed Phase 1 Specifications — Staff Report," August 13, 1990.

California Air Resources Board (ARB), Mobile Source Division, "Establishment of Reactivity Adjustment Factors, Supplement to Initial Statement of Proposed Rulemaking (Staff Report), Amendments to the Low-Emission Vehicle Program," Mail Out No. 92-59, November 13, 1992.

California Air Resources Board (ARB), "Certification and Test Procedures for Vapor Recovery Systems, Draft for February 15, 1995 workshop," 1995.

California Air Resources Board (ARB), "Proposed New Specifications for Diesel Engine Certification Fuel, Proposed Amendments to the Oxygen Specification for Natural Gas Certification Fuel, and Proposed Amendments to the Commercial Motor Vehicle Liquefied Petroleum Gas Regulations," Staff Report, August 5, 1994.

California Energy Commission (CEC), "Forecast of California Car and Truck Fuel Demand," CDC P300-83-002, staff report, January 1983.

CEC, "California Oxygenate Outlook," P300-93-002, California Energy Commission, March 1993.

CEC, "Quarterly Oil Report, Fourth Quarter 1990," P300-91-005, California Energy Commission, May 1991.

CEC, "Quarterly Oil Report, First Quarter 1992," P300-92-005, California Energy Commission, July 1992.

CEC, "Quarterly Oil Report, First Quarter 1993," P300-93-017, California Energy Commission, August 1993.

CEC, "Quarterly Oil Report, Fourth Quarter 1993," Volume XIII Number 4, P300-94-003, California Energy Commission, April 1994.

CEC, "1992 Electricity Report," P104-92-001, January 1993.

Campbell, J.H., "Gas Conditioning and Processing," 2nd ed., John M. Campbell, Norman, Oklahoma, 1970.

Chevron USA, "Reformulated Gasoline and FCC Modernization Project, Plant 10 (Application No. 9978)." Application supplied by Bay Area Air Quality Management District, San Francisco, CA, February 19, 1994.

Craig, E., S. Unnasch, and D. Lowell, "The Effect of Fuel Cycle Energy Efficiency and Transportation Efficiency on Greenhouse Gas Emissions," prepared for the California Energy Commission under Contract 500-88-003, Task 2, Work Authorization 22, by Acurex Corporation, Environmental Systems Division, Mountain View, California, March 1991.

Croes, B., and W. Carter, "Protocol for Development of Ozone Reactivity Scale for Low-emission Vehicles and Clean Fuel Regulations," Second Draft, California Air Resources Board, August 9, 1991.

Darrow, K. G., "Light-Duty Vehicle Full Fuel Cycle Emissions Analysis," GRI Topical Report, GRI-93/0472, April 1994.

Davis, B. C., "Adventures in Clean Air Act Amendments Implementation," Hydrocarbon Processing, May 1992, pp. 91-94.

Davis, B. C., "An Alternative Fuels Project Progress Report," presented at the International Symposium on Alcohol Fuels (ISAF), Firenze, Italy, November 1991.

Davis, B. C., "The Effects of Oxygenates on Ozone," presented at the International Symposium on Alcohol Fuels (ISAF), Firenze, Italy, November 1991.

Davis, B. C., "Supplying high-octane gasoline will further challenge U.S. refiners," Technology, Oil & Gas Journal, May 15, 1989, pp. 35-40.

DeLuchi, M. A., Q. Wang, and D. Sperling, "Electric Vehicles: Performance, Life-Cycle Costs, Emissions, and Recharging Requirements," Transportation Research, Vol. 23A, No. 3, May 1989, pp. 255-278.

DeLuchi, M. A., "Emissions from the Production, Storage, and Transport of Crude Oil and Gasoline," Journal of the Air & Waste Management Association, Vol. 43, November 1993, pp. 1486-1495.

DeLuchi, M. A., "Emissions of Greenhouse Gases from the use of Fossil and Nonfossil Fuels, with Emphasis on Alternative Transportation Fuels," University of California, Davis, Division of Environmental Studies, Davis, California, and Princeton University, Center for Energy and Environmental Studies, Princeton, New Jersey, March 1, 1991.

DeLuchi, M. A., "Emissions of Greenhouse Gases from the use of Transportation Fuels and Electricity, Volume 1: Main Text," ANL/ESD/TM-22, Vol. 1, prepared for Argonne National Laboratory, Center for Transportation Research, Energy Systems Division, Argonne, Illinois, November 1991.

DeLuchi, M. A., "Emissions of Greenhouse Gases from the use of Transportation Fuels and Electricity, Volume 2: Appendixes A-S," ANL/ESD/TM-22, Vol. 1, prepared for Argonne National Laboratory, Center for Transportation Research, Energy Systems Division, Argonne, Illinois, November 1993.

DeLuchi, M., Q. Wang, and D. L. Greene, "Motor Vehicle Fuel Economy, the Forgotten HC Control Strategy," ORNL-6715, Oak Ridge National Laboratory, June 1992.

Dong, Y., M. Steinberg, and R. H. Borgwardt, "An Analysis of the Hydrocarb Process for Methanol Production from Biomass," November 1992.

Edmister, W. C., and K. K. Okamoto, "Applied Hydrocarbon Thermodynamics," Part 12: Equilibrium Flash Vaporization Correlations for Petroleum Fractions," Petroleum Refiner, August 1959, pp. 117-129.

Energy Information Administration/Monthly Energy Review, "Carbon Dioxide Emission Factors for Coal: A Summary," September, 1994.

ENSR Consulting and Engineering, "Final Environmental Impact Report, Volume I, ARCO Los Angeles Refinery Clean Fuels Projects," prepared for South Coast Air Quality Management District, SCH No. 92091041, July 1993.

ENSR, "Draft Environmental Impact Report, Unocal Los Angeles Refinery, Wilmington and Carson Plants, Reformulated Gasoline Project," prepared for South Coast Air Quality Management District, SCH No. 93011013, August 1993.

- ENSR, "Final Environmental Impact Report, Volume III, Unocal Los Angeles Refinery, Wilmington and Carson Plants, Reformulated Gasoline Project," prepared for South Coast Air Quality Management District, SCH No. 93011013, November 1993.
- Engineering-Science (ES), "Draft Environmental Impact Report, Volume I, Ultramar Inc. Wilmington Refinery Reformulated Fuels Program," prepared for South Coast Air Quality Management District, SCH No. 92111042, June 1993.
- Evans, J. E., et al., "Assessment of Air Toxic Emissions from the Natural Gas Industry," Gas Research Institute, April 1994.
- Fasullo, P. A., "RVP reductions would harm U.S. gas-processing industry," Technology, Oil & Gas Journal, February 1, 1988, pp. 51-56.
- Ferrell, J. E., L. L. Wright, and J. H. Cushman, "U.S. Department of Energy's Biomass Production Program," presented at the Tenth International Symposium on Alcohol Fuels, November 1993, pp. 741-747.
- Ford, A., "The Impact of Electric Vehicles on the Southern California Edison System," Multiyear Project AQLATS.1, Subproject AQLATS.1.4, California Institute for Energy Efficiency, July 1992.
- Furey, R. L. and K. L. Perry, "Composition and Reactivity of Fuel Vapor Emissions from Gasoline-Oxygenate Blends," SAE paper 912429, Society of Automotive Engineers, 1991.
- Furey, R. L. and B. E. Nagel, "Composition of Vapor Emitted from a Vehicle Gasoline Tank During Refueling," SAE paper 860086, Society of Automotive Engineers, 1986.
- Furey, R. L. and K. L. Perry, "Vapor Pressure Characteristics of M85 Methanol Fuels," SAE Paper 912415, Society of Automotive Engineers, 1991.
- Furey, R. L. and K. L. Perry, "Vapor Pressure of Mixtures of Gasolines and Gasoline-Alcohol Blends," SAE paper 861557, Society of Automotive Engineers, 1986.
- Furey, R. L., "Volatility Characteristics of Gasoline-Alcohol and Gasoline-Ether Fuel Blends," SAE paper 852116, Society of Automotive Engineers, October 1985.
- Gannett, E., Tanker Performance and Cost, Cornell Maritime Press, Inc., Cambridge Maryland, 1969
- German, M. I., N.E. Hay, R. B. Kalisch and E. J. Hahn, Gas Facts 1991 Data, The American Gas Association, Virginia, 1992.
- Gibbs, L. M., "Additives boost gasoline quality," Technology, Oil & Gas Journal, April 24, 1989, pp.60-63.
- Graham, R. L., "Chapter 1—An Analysis of the Potential Land Base for Energy Crops in the Conterminous United States," Oak Ridge National Laboratory, 1990.

Graham, R. L., L. L. Wright, and A. F. Turhollow, "The Potential for Short-Rotation Woody Crops to Reduce U.S. CO<sub>2</sub> Emissions," Climatic Change, 22:223-238, Kluwer Academic Publishers, the Netherlands, 1992.

Hargrove, Jr., O. W., "Assessment of Coal-Based Technologies for Electric Power Generation: Emission and Cost Estimates for Methanol and SNG Production and Combustion," DCN 80-202-329-06-01, prepared for the California Energy Resources Conservation and Development Commission by Radian Corporation, June 1980.

Hendriksen, P. and R.C. Rijkeboer, "Regulated and Unregulated Exhaust Gas Components from LD Vehicles on Petrol, Diesel, LPG and CNG," TNO Industrial Research, Delft, The Netherlands, October 26, 1993.

Ho, S.P. and T. A. Renner, "Global Warming Impact of Gasoline vs. Alternative Transportation Fuels," SAE paper 901489, Society of Automotive Engineers, August 13-16, 1990.

Huey, S. and C. Castaldini, "Retrofit NO<sub>x</sub> Control Technologies for Natural Gas Prime Movers," Draft Final Report (September 1991—July 1992), prepared for the Gas Research Institute by Acurex Environmental Corporation, August 1993.

Imbrecht, C. R., et al., "Fuels Report," P300-91-018, California Energy Commission, December 1991.

Jenkins, D. M., T. A. McClure, and T. S. Reddy, "Net Energy Analysis of Alcohol Fuels," API Publication No. 4312, American Petroleum Institute, November 1979.

Johansson, A., A. Brandberg, and A. Roth, "The Life of Fuels: Motor Fuels from Source to End Use—An Energy and Emissions Systems Study of Conventional and Future Options," Ecotrafic AB, Stockholm, Sweden, March 1992.

Jones, R. O., and T. J. Lareau, "Meeting the Oxygenate Requirements of the 1990 Clean Air Act Amendments," Research Study 058, American Petroleum Institute, June 1991.

Kahn, E., Electric Utility Planning & Regulation, Second edition, American Council for an Energy-Efficient Economy, Berkeley, CA, 1991.

Katofsky, R. E., "The Production of Fluid Fuels from Biomass," PU/CEES Report No. 279, Princeton University, Center for Energy and Environmental Studies, School of Engineering and Applied Science, Princeton, New Jersey, June 1993.

Kimble, J. "Impacts on Users of Dedicated Vessels," Conference on Control of Emissions from Marine Diesel Engines, presented to California Air Resources Board, El Monte, CA, November 1990.

Kirchgessner, D. A. and S. D. Piccot, "Coal Mine Methane Emissions and Mitigation," paper 4-B, presented at the Symposium on Greenhouse Gas Emissions and Mitigation Research, August 1992.

Knight, R., et al., "1992 Electric Vehicle Technology and Emissions Update," BKI-92-100, prepared for California Air Resources Board, April 30, 1992.

Kreebe, R., "Off-Road Mobile Equipment Emission Inventory Estimate," Draft, California Air Resources Board, January 1992.

Larson, E. D. and R. E. Katofsky, "Production of Hydrogen and Methanol via Biomass Gasification," Advances in Thermochemical Biomass Conversion, Elsevier Applied Science, London, England, 1992.

Larson, E. D. and R. E. Katofsky, "Production of Methanol and Hydrogen from Biomass," PU/CEES Report No. 271, Princeton University, Center for Energy and Environmental Studies, School of Engineering and Applied Science, Princeton, New Jersey, July 1992.

Lee, S. L., et al., "Aromatics Reduction and Cetane Improvement of Diesel Fuels," Fuel Reformulation, May/June 1993, pp. 58-61.

Leppanen, O. and J. Oksanen, "Net Energy and Carbon Dioxide Balances in Efficient Ethanol Production from Barley," presented at the Tenth International Symposium on Alcohol Fuels, November 1993, pp. 797-808.

Lincoln, J. W., Driving without Gas -- Gasohol, Ethanol, Methanol, Electric Cars, Gasogens, Garden Way Publishing, 1980.

Lipari, F. and D. Keski-HynnTimer, "Aldehyde and Unburned Fuel Emissions from Methanol-Fueled Heavy-Duty Diesel Engines," SAE paper 860307, Society of Automotive Engineers, Inc., February 24-28, 1986.

Liss, W. E., and W. H. Thrasher, "Variations in Natural Gas Composition in Ten Major Urban Areas in the U.S.," presentation to the SAE Fuels and Lubricants Committee 7, February 1991.

Lott, R. A., "Emissions and Mitigation of Methane from the Natural Gas Industry," paper 4-C, presented at the Symposium on Greenhouse Gas Emissions and Mitigation Research, August 1992.

Lowi, A., "Emissions Attributable to LPG Motor Fuel Supply, Distribution, and Refueling in California," October 27, 1989.

Lyons, J. M., "Low Emission Vehicle Program Applications of San Diego Gas & Electric Co., Southern California Gas Co., Southern California Edison Co. and Pacific Gas and Electric Company," Prepared Testimony of James M. Lyons on behalf of the Western States Petroleum Association, May 2, 1994.

Mason, R.L., Kent B. Spreen and Terry L. Ullman, "Effects of Cetane Number, Cetane Improver, Aromatics, and Oxygenates on 1994 Heavy-Duty Diesel Engine Emissions," SAE paper 941020, Society of Automotive Engineers, 1994.

Melhus, O., "NO<sub>x</sub> Emission Factors from Marine Diesel Engines," EMEP Workshop on Emission from Ships, Oslo, June 1990.

Mercado, D., "An Alternative Energy Future: Greenhouse Gases," Gas Energy Review, August 1992, pp. 15-23.

Miller, D. B., T. J. Soychak, and D. M. Gosar, "Economics of Recovering CO<sub>2</sub> from Exhaust Gases," Chemical Engineering Progress, October 1986, pp. 38-46.

Montgomery, D., "Low Emission Vehicle Program Applications of San Diego Gas & Electric Co., Southern California Gas Co., Southern California Edison Co. and Pacific Gas and Electric Company," Prepared Testimony of David Montgomery on behalf of the Western States Petroleum Association, May 2, 1994.

Morgester, J. J., R. L. Fricker, and G. H. Jordan, "Comparison of Spill Frequencies and Amounts at Vapor Recovery and Conventional Service Stations in California," Journal of the Air & Waste Management Association, Vol. 42, No. 3, March 1992.

Nowell, G. P., Mercantile States and the World Oil Cartel, 1900-1939, Cornell University Press, 1994.

Nikanjam, M., "Developing the First Alternative Diesel Fuel Certified by the CARB," Fuel Reformulation, May/June 1993, pp. 58-61.

Olmstead, J., D. Sperling and Quanlu Wang, "Emission Control Cost-Effectiveness of Alternative-Fuel Vehicles," SAE paper 931841, Society of Automotive Engineers, 1993.

Pacific Gas and Electric Company, Resource An Encyclopedia of Utility Industry Terms, January 1985.

Phillips Petroleum Company, "Reference Data for Hydrocarbons and Petro-Sulfur Compounds," Bulletin No. 521, January 1984.

Piel, W. J., "Ethers will play key role in "clean" gasoline blends," Technology, Oil & Gas Journal, Dec 4, 1989, pp. 40-44.

Powars, C. A., et al., "LNG Vehicle Technology, Economics, and Safety Assessment," GRI report GRI-94/0051, February 1994.

Ranger Insurance, Propane Safety, Ranger Insurance Industrial Relations Department, Houston, Texas, February 1990.

Ross, J. A., "Low Emission Vehicle Program Applications of San Diego Gas & Electric Co., Southern California Gas Co., Southern California Edison Co. and Pacific Gas and Electric Company," Prepared Testimony of James A. Ross on behalf of the Western States Petroleum Association, May 2, 1994.

Salmon, R., M. S. Edwards, and R. M. Wham, "Production of Methanol and Methanol-Related Fuels from Coal," ORNL-5564, Oak Ridge National Laboratory, May 1980.

Sandmeyer, E. E., Ph.D., "Evaluation of Fuel Cycle Emissions on a Reactivity Basis," Robert Perry Enterprises and Transcontec, Inc., March 1, 1993.

SCAQMD, "Draft 1994 Air Quality Management Plan, Draft Appendix III-A, Current and Future Average Annual Day Emissions in the South Coast Air Basin," April 1994.

SCAQMD, "Draft 1994 Air Quality Management Plan, Appendix III-B, Current and Future Planning Emissions in the South Coast Air Basin," April 1994.

SCAQMD, "Final Air Quality Management Plan, 1991 Revision, Final Appendix III-A, 1987 Emissions Inventory for the South Coast Air Basin: Average Annual Day," July 1991.

SCAQMD, "Final Air Quality Management Plan, 1991 Revision, Final Appendix IV-A, Stationary Source Control Measures, Point Sources," July 1991.

SCAQMD, "General Instruction Book, January 1 through June 30, 1994 Emission Reporting Period", and "Supplemental Instructions for Storage Tanks and References," May 1994.

Schmidt, P. F., Fuel Oil Manual, 3rd ed., Industrial Press, Inc., New York, New York, 1969.

Schmidt, R. A., "Coal in American," Coal Week, McGraw-Hill Publishing Company, 1979.

Shearer, D. F., and D. F. Gilson, "Underground Storage Tank Vent Line Emissions from Retail Gasoline Outlets," AeorVironment Report AV-FR-92-01-204R2, prepared for WSPA, May 1994.

Sherwin, M. and D. Blum, "Liquid-Phase Methanol," EPRI AF-1291, Project 317-2, Electric Power Research Institute, December 1979.

Shremp, G., California Energy Commission, personal communication, August 1995.

Shreve, R. and J. A. Brink, Jr., Chemical Process Industries, 4th ed., McGraw-Hill Book Company, 1977.

Siegi, W. O., et al., "Speciated Hydrocarbon Emissions from the Combustion of Single Component Fuels: I—Effect of Fuel Structure," Journal of the Air & Waste Management Association, Vol. 42, July 1992, pp. 912-920.

Singh, M. and B. McNutt, "Energy and Oil Input Requirements for the Production of Reformulated Gasolines," presented at the Tenth International Symposium on Alcohol Fuels, November 1993, p. 809.

South Coast Air Quality Management District, "Draft Environmental Impact Report—Unocal Los Angeles Refinery, Wilmington and Carson Plant, Reformulated Gasoline Project," SCH No. 93011013, prepared by ENSR Consulting and Engineering, August 1993.

South Coast Air Quality Management District, "Final Air Quality Management Plan, 1991 Revision, Final Appendix IV-A, Stationary Source Control Measures, Point Sources," July 1991.

South Coast Air Quality Management District, "Final Air Quality Management Plan, 1991 Revision, Final Appendix III-A, 1987 Emissions Inventory for the South Coast Air Basin: Average Annual Day," July 1991.

Stamets, L., "California Energy Plan Hearing — April 10, 1985," California Transportation Energy Demand.

Supp, E., How to Produce Methanol from Coal, Springer-Verlag, 1990.

Suresh, K. and R. K. Pefley, "Methanol Service Station Vapor Recovery System Refueling Vapor Composition Test," prepared by Alcohol Energy Systems, Inc., for Acurex Corporation, Environmental Systems Division, February 22, 1988.

Tanghetti, A. and P. McAuliffe, "Electric Vehicles and Powerplant Emissions," California Energy Commission, Energy Forecasting and Resource Assessment Division, June 28, 1995.

Takahashi, P. K. and V. D. Phillips, "Hawaii Integrated Biofuels Research Program—Phase II," Publication No. 90-1006, Hawaii Natural Energy Institute, University of Hawaii, August 1990.

Thacker, W. L., "Pipeline View on Reformulated Gasoline Distribution," Fuel Reformulation, July/August 1993, pp. 69-71.

Thomas, D., et al., "Improve Diesel Fuel Quality with Hydrocracking," Fuel Reformulation, May/June 1993, pp. 14-17.

Thomason, L. B., "Comments on April 21, 1993 Draft CARB/Acurex Evaluation of Fuel Cycle Emissions on a Reactivity Basis," California Natural Gas Vehicle Coalition, July 6, 1993.

Timmerhaus, K. D., and T. M. Flynn, Cryogenic Process Engineering, Plenum Press, New York, 1989.

"Transportation and Global Climate Change: Long-Run Options," A Conference Exploring Options for Mobility in a Greenhouse Gas-Constrained World, Pacific Grove, California, August 1991.

Unnasch, S., et al., "Comparative Evaluation of Clean Fueled Transit Buses," Orange County Transportation Authority, Final Report, June 1993.

Unnasch, S., et al., "Comparing the Impacts of Different Transportation Fuels on the Greenhouse Effect," CEC report P500-89-001, April 1989.

Unnasch, S., "Greenhouse Gas Emissions from Corn-Based Ethanol Production and Vehicle Use," Acurex Project 6586, prepared for the National Corn Growers Association by Acurex Corporation, Environmental Systems Division, Mountain View, California, June 1990.

U.S. Department of Energy, "Fuel Cycle Evaluations of Biomass-Ethanol and Reformulated Gasoline: Summary Report—Volume I," prepared by National Renewable Energy Laboratory, under Contract No. DE-AC01-83CH10093, Oak Ridge National Laboratory, and Pacific National Laboratory, October 1992.

U.S. Department of Transportation, "The Transport of Methanol by Pipeline," prepared by Office of Research and Analysis, U.S. DOT/Transportation Systems Center, under Project Plan Agreement No. RS-530, April 1985.

U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors," Volume I: Stationary Point and Area Sources, AP-42, Fourth Edition, Research Triangle Park, North Carolina, September 1985.

U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors," Volume I: Stationary Point and Area Sources, AP-42, Fourth Edition, Chapter 1-External Combustion Sources, Research Triangle Park, North Carolina, September 1985.

U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors," Volume I: Stationary Point and Area Sources, AP-42, Fourth Edition, Chapter 3-Stationary Internal Combustion Sources, Research Triangle Park, North Carolina, September 1985.

U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors," Volume I: Stationary Point and Area Sources, AP-42, Fourth Edition, Chapter 4-Evaporation Loss Sources, Research Triangle Park, North Carolina, September 1985.

U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors," Volume I: Stationary Point and Area Sources, AP-42, Fourth Edition, Chapter 6-Food and Agricultural Industry, Research Triangle Park, North Carolina, September 1985.

U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors," Volume I: Stationary Point and Area Sources, AP-42, Fourth Edition, Chapter 9-Petroleum Industry, Research Triangle Park, North Carolina, September 1985.

U.S. Environmental Protection Agency, "Supplement A to Compilation of Air Pollutant Emission Factors," Volume I: Stationary Point and Area Sources, AP-42, Supplement A, Research Triangle Park, North Carolina, October 1986.

U.S. Environmental Protection Agency, "Preliminary Electric Vehicle Emissions Assessment," November 3, 1993.

U.S. Environmental Protection Agency, "SPECIATE Database."

"U.S. West Coast market changes seen," Oil & Gas Journal, April 24, 1989, pp. 85-86.

Unzelman, G. H., "Reformulated gasolines will challenge product-quality maintenance," Technology, Oil & Gas Journal, April 9, 1990, pp. 43-48.

Virag, D., "Low Emission Vehicle Program Applications of San Diego Gas & Electric Co., Southern California Gas Co., Southern California Edison Co. and Pacific Gas and Electric Company," Prepared Testimony of Dennis Virag on behalf of the Western States Petroleum Association, May 2, 1994.

Wang, M. Q., "Emission Reductions of Alternative-Fuel Vehicles and Implications for Vehicle and Fuel Price Subsidies," presented at the Conference on Transportation and Energy Strategies for a Sustainable Transportation System, Pacific Grove, California, August 1993.

Wang, M. Q., "Vehicle Trip Characteristics and Electric Vehicle Characteristics," prepared for the Electric Vehicle Total Energy Cycle Analysis Project. December, 1993.

Wang, Q., M. A. DeLuchi and D. Sperling, "Emission Impacts of Electric Vehicles," J. Air Waste Management, Volume 40, No. 9, pg. 1275-1284, September 1990.

Weaver, C. S. and D. B. McGregor, "Controlling Locomotive Emissions in California Technology, Cost Effectiveness, and Regulatory Strategy," prepared for California Air Resources Board under Contract No. A032-169, October 13, 1993.

Webb, M. and P. Martino, "Fugitive Hydrocarbon Emissions from Petroleum Production Operations," AWMA 92-66.11, presented at the 85th Annual Meeting and Exhibition of the Air & Waste Management Association, Missouri, June 1992.

Western States Petroleum Association (WSPA), "Draft Paper on Marginal Emissions Relating to CARB Fuel-Cycle Emissions Study," attached to letter from Gina Grey, dated September 23, 1993.

Western States Petroleum Association (WSPA), Comments on the 1994 AQMP (Air Quality Management Plan) and the South Coast Air Quality Management District's Response, 1994.

Wheeler, R., Mutual Propane, personal communication, January 6, 1994.

Wilbur, C. T., Pounder's Marine Diesel Engines, Sixth edition, Butterworth and Co., 1986.

Williams, B., "Reformulated fuels set the stage for U.S. supply pinch, price spikes," News, Oil & Gas Journal, July 9, 1990, pp. 21-22.

Williams, B., "U.S. refiners may face gasoline supply crunch in driving season," News, Oil & Gas Journal, June 5, 1989, pp. 23-28.

Williams, B., "U.S. refiners scramble to protect margins cut by crude price jump," News, Oil & Gas Journal, August 17, 1987, pp. 17-19.

Wood, P. R., "New Ethanol Process Technology Reduces Capital and Operating Costs for Ethanol Producing Facilities," Fuel Reformulation, July/August 1993, pp. 56-64.

Wright, J. D. and D. A. Feinberg, "Comparison of the Production of Methanol and Ethanol from Biomass," presented at the Tenth International Symposium on Alcohol Fuels, November 1993, pp. 797-808.

Wright, L. L. and J. H. Cushman, "Biofuels Feedstock Development Program"/Graham, R. L., et al., "Biomass Fuel Costs Predicted for East Tennessee Power Plant," Oak Ridge National Laboratory, Environmental Sciences Division, Oak Ridge, Tennessee, undated.

Wyman, C. E., et al., "Ethanol and Methanol from Cellulosic Biomass," National Renewable Energy Laboratory, 1990.

